# Alternatives Analysis

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**December 2007**

## Alternatives Analysis

### Executive Summary

In 2006, Brazos Electric retained Black & Veatch to assist in the preparation of a long-range power supply study. As part of the 2006 Power Supply Study, Brazos Electric and Black & Veatch evaluated (i) a wide range of natural gas-fired and coal-fired generation technologies and plant sizes, (ii) renewable energy technologies, and (iii) proposals received in response to a request for proposals ("RFP") for capacity and energy. Fossil-fuel technologies evaluated include natural gas-fuelled simple cycle combustion turbines and combined cycle configurations, and coal-fuelled pulverized coal, circulating fluidized bed, and integrated gasification combined cycle units. Renewable technologies evaluated include solid biomass, biogas, wind, solar and hydroelectric. RFP responses were sought for renewable energy, conventional generating units, and nuclear; however, no nuclear or renewable alternatives were proposed. The Final Report of the 2006 Power Supply Study is included in this Alternatives Analysis as Appendix A.

The following significant changes have occurred since completion of the 2006 Power Supply Study:

1. One assumption in the 2006 Power Supply Study was that Brazos Electric would own half of the capacity (393 MW) from the Hugo 2 coal-fired unit addition to be constructed with Western Farmers Electric Cooperative (Western Farmers). In March 2007, Brazos Electric and Western Farmers terminated negotiations associated with Brazos Electric's potential participation in Hugo 2.

2. During July and August 2007, Brazos Electric and its wholly owned subsidiary, Brazos Sandy Creek Electric Cooperative, Inc. (BSCEC), executed agreements with Sandy Creek Energy Associates, L.P. (SCEA) for capacity and energy from the Sandy Creek Energy Facility (Sandy Creek). Sandy Creek is a 900 MW supercritical pulverized coal generating plant to be constructed near Riesel in McLennan County, Texas. Sandy Creek is scheduled to begin commercial operations in July 2012. Brazos Electric executed a 150 MW Power Purchase Agreement (PPA) with SCEA. BSCEC acquired a twenty-five percent, or 225 MW, ownership share in the Sandy Creek plant, and will supply the capacity and energy to Brazos Electric under a separate PPA. On July 12, 2007, the Rural Utilities Service ("RUS") approved a waiver of the requirements of (i) Sections 6.2 and 6.13 of the RUS Loan Contract, and (ii) Section 4.10 of the Consolidated Mortgage, Security Agreement and Financing Statement to permit Brazos Electric to acquire 375 MW of capacity in Sandy Creek (with the understanding that Brazos Electric would form a special purpose entity to acquire the ownership interest). RUS approved the PPA on July 16, 2007.

3. Brazos Electric contracted with Tarrant Regional Water District for an additional 1 million gallons per day (1,120 acre-feet/year) of water supply. Additional water will also be available from Walnut Creek Special Utility District in 2012. With these additions, total available water supplies are adequate to permit addition of a

second combined cycle unit at the Jack County Generation Facility that utilizes a wet condenser and cooling towers. The reduction in costs associated with elimination of the need for an air-cooled condenser makes the Jack County combined cycle unit addition Brazos Electric's most economic alternative.

2006 Power Supply Study Table 10-1, Capacity Expansion Plan Resource Additions, lists five base expansion plans. Three of the capacity expansion plans include only self-build resource additions. Two of the capacity expansion plans include two Power Purchase Agreements (PPAs) identified as low cost PPAs based the proposals received (Brazos Electric's PPA and BSCEC ownership in the Sandy Creek Energy Facility resulted from one such proposal). Each of the plans included a 2x1 combined cycle unit addition in 2010 or 2011.

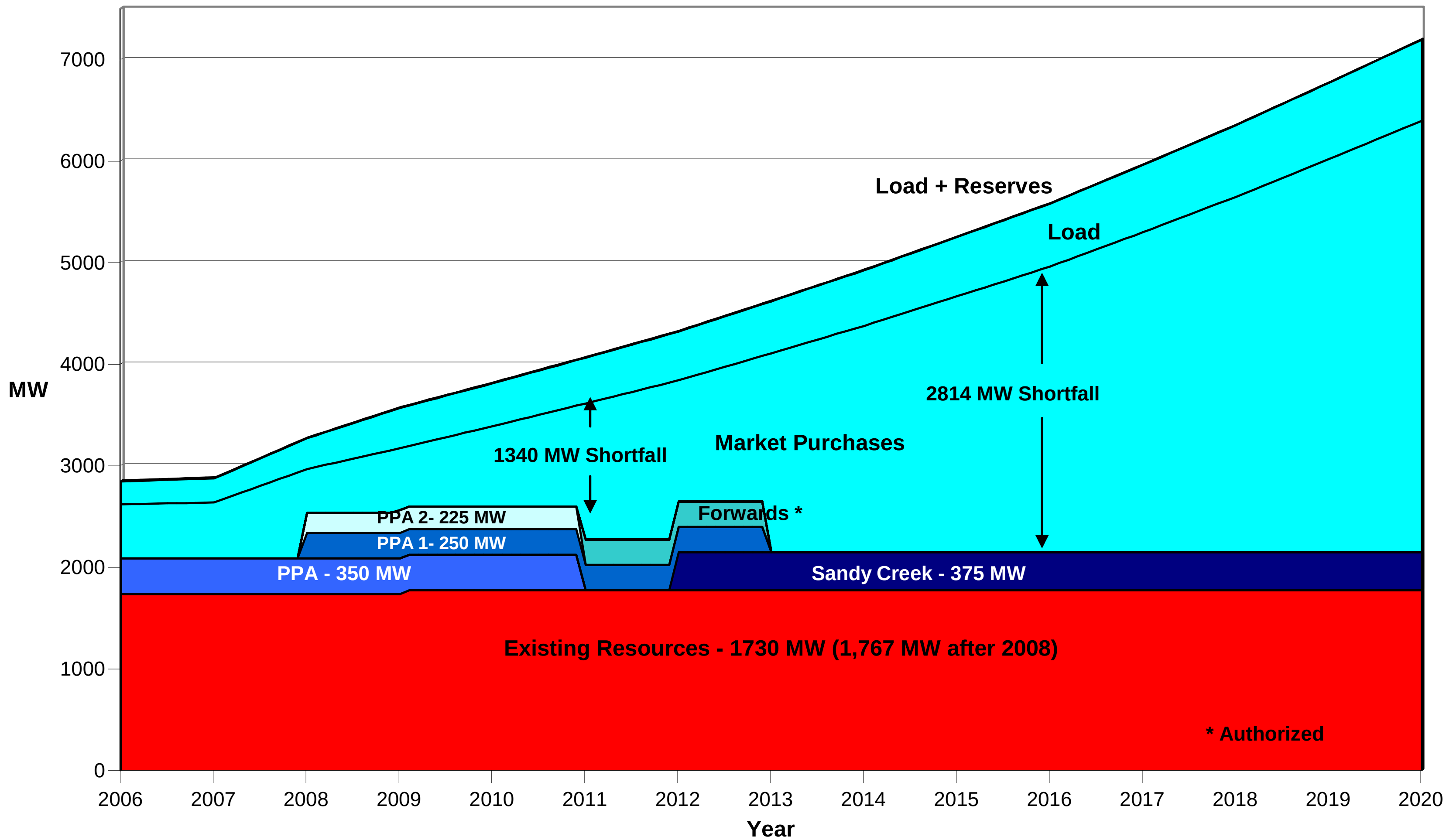
In response to the 2006 Power Supply Study recommendations, Brazos Electric retained Fluor Enterprises, Inc. to perform conceptual design studies for natural gas-fired combined cycle unit additions at the Jack County and Johnson County Generating Facilities, and at an as yet undetermined greenfield site (Greenfield CC). The estimated capacity, capital costs, and cost per KW for these unit self-build alternatives are being used in the final evaluation of the alternatives. A nominal 600 MW combined cycle, duct-fired capacity addition at the Jack County Generating Facility is the lowest cost self-build alternative, and has the earliest completion date.

In 2007, Brazos Electric retained Burns & McDonnell to update the 2002 Site Selection Study to evaluate the feasibility of combined cycle unit additions at the existing Jack County and Johnson County Generating Facilities. The report, Update to 2002 Site Selection Study, is attached as Appendix B. Conclusions reached from the study include: "Subject to the limitations that may be imposed by regulatory and permitting agencies, both the Jack County and Johnson County site areas are capable of accommodating the development and insertion of additional gas-fired generation. Both sites scored very well in relative comparison to previously examined sites in the 2002 Study and either site appears to be a viable option".

Brazos Electric is currently updating its evaluations comparing self-build and power supply purchase alternatives. Updated long-term proposals have been, or will be, obtained from several ERCOT market participants in December. The results of these analyses will be provided in connection with a loan application or, should the results favor a power purchase alternative, a request to RUS for approval of a long-term agreement.

A summary of Brazos Electric's current capacity, demand, and reserves is shown in Figure 1. A Load/Capacity Comparison is shown in Table 1. Demands are based on the 2006-2025 Load Forecast, which was approved by the Rural RUS in August 2007. Since being approved by RUS, the Load Forecast has been adjusted downward because of the loss of two industrial loads.

**Figure 1, Member System Load, Reserves, Resources**
**Existing (as of December 2007)**



# Table 1, Load - Capacity Comparison

## Member System Beneficiary and Non-Member Load Requirements
## Updated Load Forecast 2006-2025

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System Load (MW)** | | | | | | | | | | | | | | | | | | | | |
| Members System Coincident Peak [1][2] | 2,536 | 2,557 | 2,874 | 3,076 | 3,287 | 3,505 | 3,729 | 3,988 | 4,252 | 4,536 | 4,821 | 5,152 | 5,491 | 5,853 | 6,223 | 6,651 | 7,090 | 7,558 | 8,036 | 8,590 |
| Losses @ 2.1% | 53 | 53 | 62 | 66 | 71 | 75 | 80 | 86 | 91 | 97 | 103 | 111 | 118 | 126 | 133 | 143 | 152 | 162 | 172 | 184 |
| Sub-Total | 2,589 | 2,610 | 2,936 | 3,142 | 3,357 | 3,580 | 3,809 | 4,073 | 4,344 | 4,633 | 4,924 | 5,262 | 5,609 | 5,979 | 6,356 | 6,794 | 7,242 | 7,721 | 8,209 | 8,774 |
| Non-Member Diversified Load (incl Losses) | 24 | 24 | 25 | 26 | 27 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 |
| Total | 2,613 | 2,634 | 2,961 | 3,167 | 3,384 | 3,607 | 3,837 | 4,102 | 4,374 | 4,664 | 4,956 | 5,295 | 5,643 | 6,013 | 6,392 | 6,831 | 7,280 | 7,759 | 8,248 | 8,815 |
| Reserve Requirements [3] | 227 | 236 | 304 | 396 | 423 | 426 | 455 | 513 | 547 | 583 | 620 | 662 | 705 | 752 | 799 | 854 | 910 | 970 | 1,031 | 1,102 |
| System Peak w/ Reserve Req. | 2,840 | 2,870 | 3,265 | 3,563 | 3,807 | 4,033 | 4,291 | 4,615 | 4,920 | 5,247 | 5,576 | 5,957 | 6,348 | 6,765 | 7,191 | 7,685 | 8,190 | 8,729 | 9,279 | 9,917 |
| **Resource Capacity (MW)** | | | | | | | | | | | | | | | | | | | | |
| Miller Plant (Units 1,2,3) | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 | 403 |
| Miller Plant (Units 4,5) | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 |
| N. Texas Plant (Units 1,2,3) [5] | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 |
| Jack County | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 | 575 |
| Johnson County | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 |
| Sandy Creek | | | | | | | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 |
| San Miguel PPA | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 |
| Hydro PPA | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 | 54 |
| Contracted Resources | 350 | 350 | 800 | 825 | 825 | 250 | 250 | | | | | | | | | | | | | |
| Other Purchase Contracts | 800 | 750 | 500 | | | 200 | 200 | | | | | | | | | | | | | |
| Demand Reduction Program | | | 25 | | | | | | | | | | | | | | | | | |
| Available Capacity | 2,880 | 2,830 | 3,055 | 2,555 | 2,555 | 2,180 | 2,555 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 | 2,105 |
| **Surplus (Deficit)** | 40 | (40) | (211) | (1,009) | (1,252) | (1,854) | (1,737) | (2,510) | (2,816) | (3,142) | (3,471) | (3,852) | (4,244) | (4,661) | (5,086) | (5,580) | (6,085) | (6,625) | (7,175) | (7,813) |

Notes for Table 1:
[1] Historical actual demands for 2006 and 2007
[2] Forecasted demands based on 2006-2025 Load Forecast - approved to RUS in August 2007
[3] Reserve requirements computed at 12.5% (recommended by ERCOT Board); requirements computed for ERCOT load only

Table 2 lists the annual energy requirements and sources for 2009, 2012 and 2015, assuming no resource additions and that Brazos Electric continues to rely on market purchases for incremental energy. As seen by the percentage of total energy requirements provided by each source, Brazos Electric's reliance on market purchases of energy remains substantial and increases over the time period.

**Table 2, Sources of Energy (GWH)[1]**

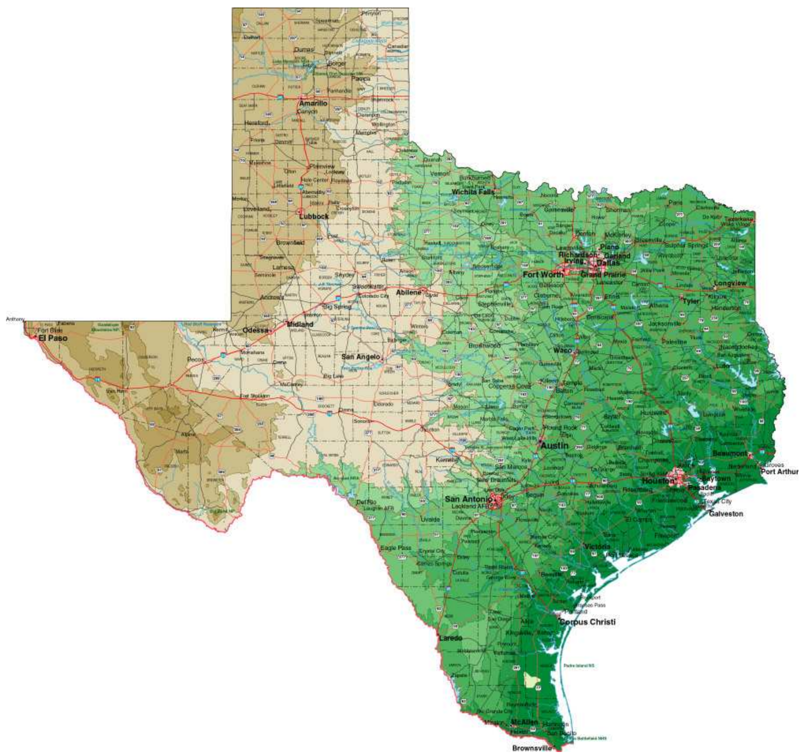
| | 2009 | | 2012 | | 2015 | |
|---|---|---|---|---|---|---|
| **Source** | **(GWH)** | | **(GWH)** | | **(GWH)** | |
| Miller Plant | 255.7 | 1.87% | 652.7 | 3.99% | 743.1 | 3.79% |
| North Texas Plant | 1.6 | 0.01% | 7.2 | 0.04% | 9.3 | 0.05% |
| Jack County Plant | 4,115.1 | 30.15% | 3,567.4 | 21.80% | 3,701.3 | 18.87% |
| Johnson County Plant | 1,706.0 | 12.50% | 1,082.9 | 6.62% | 1,163.8 | 5.93% |
| San Miguel | 1,421.1 | 10.41% | 1,423.5 | 8.70% | 1,417.3 | 7.23% |
| Whitney/M. Shep. | 78.1 | 0.57% | 78.1 | 0.48% | 78.1 | 0.40% |
| Sandy Creek | 0.0 | 0.00% | 854.7 | 5.22% | 1,679.8 | 8.57% |
| **Total Generation** | 7,577.6 | 55.53% | 7,666.5 | 46.85% | 8,792.7 | 44.83% |
| Market Purchases | 6,069.2 | 44.47% | 8,696.2 | 53.15% | 10,819.0 | 55.17% |
| **Total Requirements** | 13,646.8 | | 16,362.7 | | 19,611.7 | |

[1] Based on 12/5/07 Market Forwards Only case.

# Final Report

## Brazos Electric Cooperative

## 2006 Power Supply Study




**February 2007**

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# Acronym List

| | |
|---|---|
| ACES | ACES Power Marketing |
| AGC | Automated General Control |
| BACT | Best Available Control Technology |
| Brazos Electric | Brazos Electric Power Cooperative, Inc. |
| Btu | British Thermal Unit |
| B&M | Burns & McDonnell |
| CAIR | Clean Air Interstate Rule |
| Calpine | Calpine Energy Services |
| CAMR | Clean Air Mercury Rule |
| CaO | Calcium Oxide |
| CC | Combined Cycle |
| CFB | Circulating Fluidized Bed |
| CFR | Code of Federal Regulations |
| CO | Carbon Monoxide |
| COD | Commercial Operation Date |
| CPI | Consumer Price Index |
| CPWC | Cumulative Present Worth Cost |
| CT | Combustion Turbine |
| CTG | Combustion Turbine Generator |
| DEGS | Duke Energy Generation Services |
| DI | Diffuse Insolation |
| DNI | Direct Normal Insolation |
| $/Mwh | Dollars per Megawatt-hour |
| EPA | Environmental Protection Agency |
| EPC | Engineering, Procurement, and Construction |
| ERCOT | Electric Reliability Council of Texas |
| FCR | Fixed Charge Rate |
| FGD | Flue Gas Desulfurization |
| FOM | Fixed Operation and Maintenance |
| G&T | Generation and Transmission |
| GE | General Electric |
| GF | Greenfield site |
| GT | Simple Cycle Combustion Turbine |
| GWh | Gigawatt-hour |
| HHV | Higher Heater Value |

| | |
|---|---|
| HPC | High-Pressure Compressor |
| HPT | High-Pressure Turbine |
| HRSG | Heat Recovery Steam Generator |
| Hz | Hertz |
| IDC | Interest During Construction |
| IRAF | Interest Rate Adjustment Factor |
| ISO | International Organization for Standardization |
| IGCC | Integrated Gasification Combined Cycle |
| kV | Kilovolt |
| LD | Liquidated Damages |
| LFG | Landfill Gas |
| LHV | Lower Heating Value |
| LNG | Liquefied Natural Gas |
| LOLP | Loss of Load Probability |
| LPC | Low-Pressure Compressor |
| LPT | Low-Pressure Turbine |
| LS Power | LS Power Associates LLP |
| MBtu | Million BTU |
| MW | Megawatt |
| NDE | Nondestructive Examination |
| NEL | Net Energy for Load |
| NGPL | Natural Gas Pipeline Company |
| NI | Nuclear Island |
| NOAA | National Oceanic and Atmospheric Administration |
| $NO_x$ | Nitrogen Oxide |
| NRC | Nuclear Regulatory Commission |
| O&M | Operations and Maintenance |
| Odessa | Texas Independent Energy, Odessa Ector Power Partners |
| PC | Pulverized Coal |
| PM | Particulate Matter |
| PPA | Purchase Power Agreement |
| ppm | Parts per Million |
| ppmvd | Parts per Million Volumetric Dry |
| PRB | Powder River Basin |
| PTC | Production Tax Credit |
| PV | Photovoltaics |
| R&D | Research and Development |

| | |
|---|---|
| RFP | Request for Power Supply Proposal |
| RFP | Request for Proposal |
| RH | Relative Humidity |
| rpm | Revolutions per Minute |
| RUS | Rural Utilities Service |
| SAS | Statistical Analysis System |
| SC | Simple Cycle |
| scf | Standard Cubic Feet |
| SCR | Selective Catalytic Reduction |
| SEGS | Solar Electric Generating Station |
| SES | Stirling Energy Systems |
| SNCR | Selective Noncatalytic Reduction |
| SNL | Sandia National Laboratories |
| $SO_2$ | Sulfur Dioxide |
| $SO_3$ | Sulfur Trioxide |
| SRU | Sulfur Recovery Unit |
| ST | Steam Turbine |
| STG | Steam Turbine Generator |
| Strategist | Strategist and Proview™ software |
| Suez | Suez Energy and Wise County Power Company |
| Tbtu | Trillion Btu |
| TCR | Transmission Congestion Rights |
| TI | Turbine Island |
| USDA | United States Department of Agriculture |
| US DOE | United States Department of Energy |
| VOM | Variable Operation and Maintenance |
| WFEC | Western Farmers Electric Cooperative |
| WTE | Waste-to-Energy |

# 1.0 Study Approach

The Brazos Electric Power Cooperative, Inc. (Brazos Electric) Power Supply Study process consists of five key stages: data collection, request for power supply proposal (RFP) issue and bid response evaluation, data analysis, data modeling, and report writing and approvals. Throughout this process, data for supply-side alternatives were compiled, reviewed, screened for appropriateness, and modeled using industry approved methods and tools, taking into account any special considerations and sensitivities to derive the least-cost expansion plan for Brazos Electric.

## 1.1 Data Collection

The data collection stage includes the compilation and review of historical and forecast data. These data include electric supply resources and operating data; load and energy requirements and supply contracts; fuel prices and availability; emission allowance prices, and purchased power data. The data provided by Brazos Electric, were either developed in-house by Brazos Electric or developed by others on behalf of Brazos Electric.

## 1.2 RFP Process

As part of the Power Supply Study, an RFP was issued for supply of capacity and energy both for short-term and long-term durations. The RFP process allowed purchase options to be evaluated along with self-build alternatives, with any purchases made through this RFP beginning as early as January 1, 2008. The RFP was issued on August 7, 2006. A total of nine companies submitted 15 proposals. Proposals included simple cycle, combined cycle (CC), and pulverized coal (PC) generating units. Although requested in the RFP, bids were not received for nuclear or renewable technologies.

The bids received in response to the RFP were summarized and evaluated initially using a busbar screening analysis. The short-term and long-term bids were evaluated separately. In addition to the short-term and long-term bids, some “Expressions of Interest” were also received from interested companies to jointly participate with Brazos Electric in development of new power plants. These expressions of interests were also evaluated separately.

## 1.3 Data Screening

Although there is a wide range of technologies and plant sizes that could provide future generating resources to Brazos Electric, representative technologies and sizes were selected for this Power Supply Study. To identify and select the most appropriate technologies for Brazos Electric, the technologies were limited to units that could provide approximately 100 megwatt (MW) blocks of capacity or more, utilize proven technologies, and utilize a mix of peaking, intermediate, and baseload configurations. Various gas fired and solid fuel options were evaluated. The self-build alternatives evaluated included: two-unit LM6000 simple cycle, LMS100 simple cycle, 7FA simple cycle, 7FA CC, 500 MW supercritical PC, 500 MW lignite fired circulating fluidized bed (CFB), a 7EA repowering, and an integrated gasification combined cycle (IGCC) alternative.

As part of the Power Supply Study, a prescreening analysis of these site-specific, self-build alternatives was conducted on a busbar basis to categorize options as peaking, baseload, or intermediate load. This screening analysis included development of busbar curves that showed the capacity factors over which certain technologies were competitive. The busbar analysis compares the total cost (capital, fuel, and fixed and variable operations and maintenance [O&M]) of all the alternatives on a dollars per megawatt-hour ($/MWh) basis at various capacity factors.

## 1.4 Data Modeling

The data analysis stage includes the modeling of data for the new generating alternatives gathered during the data collection stage. Brazos Electric used its own in-house software resources to perform the data modeling. The modeling was done by Brazos Electric using the New Energy Strategist and Proview Software ™. The input data for the new generating alternatives were developed by Black & Veatch. This software evaluates combinations of alternatives and determines the combination that exhibits the lowest cumulative present worth revenue requirements, while maintaining user-defined reliability, environmental, and other system criteria. This least-cost plan was based on a planning horizon from 2006 to 2035. The modeling results produced a base reference expansion plan and two competing plans. In addition, two plans including power purchases from the RFP process were evaluated. Black & Veatch then reviewed the input and output data of this model to verify the results.

## 1.5 Specific Issues

In addition to cost considerations, other issues were factored into the Power Supply Study. These additional considerations included capacity and forecast issues. The following outlines the specific issues that were considered in addition to the base case least-cost plan to evaluate the sensitivity of Brazos Electric's forecasts:

- High Load and Energy Forecast.
- Low Load and Energy Forecast.

- High Fuel Price Forecast.
- Low Fuel Price Forecast.
- High Emission Price Forecast.
- Low Emission Price Forecast.

Most of these issues were modeled as sensitivities to the base case assumptions. The sensitivity modeling helped to ensure that the reference plan selected was economically and environmentally responsible for Brazos Electric.

# 2.0 Existing System Description

## 2.1 General Overview

Brazos Electric is Texas' largest and oldest generation and transmission electric cooperative. Brazos Electric provides electric service to 68 counties, 17 electric distribution cooperatives, and three municipal electric systems under full requirements wholesale contracts. Brazos Electric owns, operates, and maintains over 2,559 miles of transmission line consisting of 1,280 miles of 69 kilovolt (kV), 1,183 miles of 138 kV, and over 96 miles of 345 kV lines. Brazos Electric is interconnected with 16 transmission and distribution entities, and is a member of the Electric Reliability Council of Texas (ERCOT). Brazos Electric's generating resources include the Jack County, Johnson County, Miller, and North Texas plants as summarized in Table 2-1.

Table 2-1
Existing Generating Facilities (as of December 2006)

| Plant Name | Location (County) | Unit No. | Unit Type(1) | Primary Fuel Type | Commercial In-Service (MM/YYYY) | Net Summer Capacity (MW) |
|---|---|---|---|---|---|---|
| Jack County | Jack | 1 | CC | Natural Gas | 2/2006 | 600 |
| Johnson County | Johnson | 1 | CC | Natural Gas | 1/1997 | 258 |
| R. W. Miller | Palo Pinto | 1 | ST | Natural Gas | 10/1968 | 75 |
| R. W. Miller | Palo Pinto | 2 | ST | Natural Gas | 07/1972 | 120 |
| R. W. Miller | Palo Pinto | 3 | ST | Natural Gas | 08/1975 | 208 |
| R. W. Miller | Palo Pinto | 4 | GT | Natural Gas | 07/1994 | 104 |
| R. W. Miller | Palo Pinto | 5 | GT | Natural Gas | 07/1994 | 104 |
| North Texas | Parker | 1 | ST | Natural Gas | 06/1958 | 18 |
| North Texas | Parker | 2 | ST | Natural Gas | 08/1958 | 18 |
| North Texas | Parker | 3 | ST | Natural Gas | 07/1963 | 39.5 |

(1)CC - combined cycle; ST - steam turbine; GT - simple cycle combustion turbine.

## 2.2 Brazos Electric Generating Facilities

The generating facilities currently owned and operated by Brazos Electric include the Jack County, Johnson County, Miller, and North Texas plants. Collectively, these plants consist of a 2x1 CC plant (Jack County), a 1x1 CC plant (Johnson County), six (five operating) conventional gas fired steam generating units (Miller and North Texas), and two simple cycle combustion turbine (CT) generating units (Miller). The total summer net capability of Brazos Electric's existing generating units is 1,505 MW.

The Jack County plant is interconnected to the 138 kV transmission system and consists of a 2x1 CC with supplemental firing. Jack County has a total net summer capacity of 600 MW, including approximately 131 MW from the supplemental firing.

The Johnson County plant is interconnected to the 138 kV transmission system and consists of a 1x1 CC. The plant has a summer net capacity of 258 MW.

The Miller plant is located in Palo Pinto County, and is interconnected to the 69 kV and 138 kV transmission systems. The Miller plant consists of three conventional gas fired steam generating units and two simple cycle CT generating units. The three gas fired steam generating units (Units 1, 2, and 3) have a combined summer net capacity of 403 MW. The two simple cycle CT generating units (Units 4 and 5) have a combined summer net capacity of 208 MW.

The North Texas plant is located in Parker County, and is interconnected to the 138 kV transmission system. The North Texas plant consists of two operating gas fired steam generating units (Units 1 and 2) with a combined net summer capacity of 36 MW. A third North Texas unit (Unit 3) has a net summer capacity of 39.5 MW but is currently not being operated because of emissions limitations.

Brazos Electric and Western Farmers Electric Cooperative (WFEC) plan to jointly develop the Hugo 2 Project, a 786 MW supercritical PC unit which will operate on Powder River Basin (PRB) coal. Brazos Electric will own 393 MW of Hugo 2, which will be located at WFEC's existing Hugo site near Fort Towson, Oklahoma. Construction of the unit at an existing site will allow Hugo 2 to utilize the existing coal transportation and handling systems, as well as the existing water supply system, thus lowering the cost. Hugo 2 is anticipated to begin commercial operation in 2012.

## 2.3 Generating Fleet Reliability

Brazos Electric currently has nine independent generating units currently installed and operating within their generating fleet. The net summer capacity of these units ranges from 18 MW to 600 MW and consists of natural gas fired simple cycle, CC, and steam turbine (ST) generating units. The addition of coal fired Hugo 2 in 2012 will further enhance reliability as well as provide diversity to Brazos Electric's fuel supply. Each unit has unique historical and projected availability characteristics due to either planned or unplanned outages. The economic and reliability effects of the availability characteristics of Brazos Electric's generating units are considered in this study in order to produce a future expansion plan that is robust and reliable.

## 2.4 Generating Fleet Efficiency

The Brazos Electric generating fleet is committed and dispatched according to each unit's overall efficiency and ability to produce electricity at the lowest possible cost. The two components considered when determining dispatch order are the cost of a unit's fuel relative to its heat content and the unit's efficiency. Table 2-2 lists Brazos Electric's existing generating units and their corresponding average full load net heat rates. The economics of generator unit efficiencies are considered in this study to produce a future expansion plan that is not only robust and reliable but also economical.

Table 2-2
Existing Generating Fleet Efficiency

| Unit | Average Full Load Net Heat Rate (Btu/kWh) |
|---|---|
| Jack County | 6,850 |
| Johnson County | 7,272 |
| Hugo 2 | 9,284 |
| R. W. Miller 1 | 11,201 |
| R. W. Miller 2 | 10,182 |
| R. W. Miller 3 | 10,366 |
| R. W. Miller 4 | 11,767 |
| R. W. Miller 5 | 11,797 |
| North Texas 1 | 14,624 |
| North Texas 2 | 13,877 |
| North Texas 3 | 11,592 |

## 2.5 Firm Purchased Power Contracts

Brazos Electric currently has three firm purchase power contracts in place, summarized as follows.

### *2.5.1 San Miguel Electric Cooperative*

Brazos Electric purchases 195.5 MW of baseload lignite fueled generating capacity from San Miguel Electric Cooperative, Inc., under a long-term contract.

### *2.5.2 Southwest Power Administration and Brazos River Authority*

Brazos Electric purchases 54 MW of hydroelectric generating capacity from Southwest Power Administration and Brazos River Authority under long-term contracts.

### *2.5.3 BP Energy Company*

Brazos Electric purchases 350 MW of capacity and energy under a 5 year (2006 through 2010) power purchase agreement with BP Energy Company.

## 2.6 Firm Power Sales Agreements

Brazos Electric has no firm power sales agreements. When economical, Brazos Electric sells power on the spot market.

## 2.7 ACES Power Marketing

Brazos Electric supplies capacity and energy to its customers through purchases of monthly, seasonal or annual fixed price forward contracts and call options, or other short-term market purchases. ACES Power Marketing (ACES) acts as an agent for Brazos Electric in the ERCOT short-term market, buying and selling power and natural gas to serve members' loads.

## 2.8 Renewable Power

Except for the Southwestern Power Administration and Brazos River Authority hydroelectric contracts, Brazos Electric does not currently have any units that generate power using renewable resources. Opportunities to utilize renewable resources were considered in this Power Supply Study.

## 2.9 Transmission and Interconnections

The Brazos Electric transmission system consists of over 2,559 circuit-miles of bulk power transmission facilities operating at three voltage levels: 69 kV, 138 kV, and 345 kV. These are interconnected with 16 transmission and distribution entities within Texas.

## 2.10 Planning Reserve Margin

Brazos Electric uses a planning reserve margin criterion of 12.5 percent for providing reliable electricity to its customers. The 12.5 percent planning reserve margin is accepted by ERCOT and is consistent with requirements in other regions of the nation. The planning reserve margin covers uncertainties in extreme weather, forced outages of generators, and uncertainty in load projections. Brazos Electric maintains the reserve margin only for firm load obligations. Interruptible load is not considered in the planning reserve margin.

## 2.11 Planned Unit Retirements

Brazos Electric currently does not have any planned unit retirements. Although the older Miller and North Texas gas fired units represent potential future retirements, for the purpose of this study these units were not retired. Retirement of any of these units would increase Brazos Electric's need for capacity. These units are discussed in Section 9.0 of this study.

## 2.12 Emission Rates

As further discussed in Section 6.0, future environmental regulations including the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) are expected to result in cap-and-trade emissions allowance programs that will affect the cost of generation for the Brazos Electric fleet. Section 10.0 describes how emissions allowance costs have been considered in the economic evaluation.

# 3.0 Forecasts and Economic Parameters

This section summarizes the forecasts and economic parameters utilized throughout the Power Supply Study. As described in this section, the forecast annual peak demand and energy requirements were provided by Brazos Electric, while fuel and emission price forecasts were developed by ACES. The economic parameters for this study were developed by Black & Veatch. The remainder of this section provides further details related to these forecasts and economic parameters.

## 3.1 Load Forecast

The load forecast is an important consideration in the overall Power Supply Study process as it allows for determination of capacity requirements through comparison with capacity resources and reserve margin requirements (described in Section 4.0). Brazos Electric has provided a forecast of annual peak demand and energy requirements for 2007 through 2022 under base case assumptions, as well as for scenarios assuming high and low load growth. The methodology used in developing these forecasts is presented herein. It should be noted that the peak demand and energy requirements forecasts are held constant from 2023 through 2035 for the economic evaluation presented in Section 10.0.

### *3.1.1 Load Forecast Methodology*

The Brazos Electric Load Forecast was conducted in accordance with the Brazos Electric Load Forecast Work Plan, which provides a detailed description of the method for completion of the joint member and generation and transmission studies (G&T). Brazos Electric regularly prepares demand and energy forecasts to meet its own internal needs. Because it is a borrower from the Rural Utilities Service (RUS) of the United States Department of Agriculture (USDA), Brazos Electric is subject to the planning requirements of the RUS under the Code of Federal Regulations (CFR).

RUS requires Brazos Electric to prepare a document every other year known as the Load Forecast. The Load Forecast generally consists of 20 year forecasts of annual peak demand and energy for (i) Brazos Electric’s total member cooperative load, (ii) Brazos Electric’s total load, including member and nonmember load, and (iii) Brazos Electric’s integrated system load. The integrated system load includes the entire non-member load and that portion of the member cooperative load served by Brazos Electric resources including incremental resources. The remainder of Brazos Electric’s member cooperative load is served via wholesale power purchases from other utilities and is referred to as the isolated system load. The Load Forecast is developed to provide the most probable forecasts of the future power requirements of Brazos Electric’s member and nonmember customers. The Load Forecast is prepared from a "bottom-up" standpoint; that is, load forecasts are determined for each individual member cooperative and wholesale customer. These individual forecasts, taking into account the distribution losses and Brazos Electric system requirements, and diverse economic circumstances are aggregated to develop the Load Forecast.

Historical customer and usage information is taken from RUS Form 7, which is reported annually. Brazos Electric maintains this information internally. All data, models, and forecasts developed for this Load Forecast are annual in periodicity. All economic and demographic information were acquired from an independent vendor. The climatological data in the Load Forecast database consists primarily of annual Cooling and Heating Degree Days for the major National Oceanic & Atmospheric Administration (NOAA) weather stations in Brazos Electric's service area. Estimation of the econometric models, determination of statistical properties, and generation of forecasts all were accomplished using the Statistical Analysis System (SAS), Release 8.0 for Windows.

Multiple regression econometric modeling techniques are chosen to model the suitable classifications of each member cooperative and wholesale customer. Econometric modeling is utilized for the residential and small commercial sectors of the member cooperatives. The member cooperatives then forecast power requirements for the other classes (irrigation, large commercial, security lights, own use, public street and highway, etc.). Brazos Electric personnel test numerous models regarding customer and energy usage per consumer for the residential and small commercial classifications of each member cooperative. The models are presented to and discussed with the contact person for each member cooperative associated with the Load Forecast process allowing for discussion of the characteristics of the member's service area, short-term expectations, and in-depth discussions regarding the validity of the explanatory variables found in the models. After agreement is reached on a final set of models, these forecasts are included by the members in reporting their individual forecasts by classification within their individual load forecasts. Each member forecast is the result of a joint forecasting effort between Brazos Electric and the individual member. The summation of the individual wholesale customer system requirements comprises the Brazos Electric system forecast.

The current Load Forecast methodology has been in place for over a decade; the previous five RUS-approved Load Forecasts have all been conducted using a similar process. This composite forecast is the official forecast as it presents a robust total beneficiary forecast, and directly reflects the member cooperatives' economic and engineering judgment.

### *3.1.2 Historical Peak Demand and Net Energy for Load*

Brazos Electric has historically experienced annual peaks in the summer period. Table 3-1 indicates the historical system peak from 2002 through 2006. The summer peak demand increased from 1,928 MW to 2,613 MW during this period, which is an average annual growth rate of approximately 7.9 percent. However, some annual percent increases have exceeded 10 percent. Figure 3-1 shows the historical peak demand as well as forecast peak demand through 2022.

Table 3-1
Historical Peak Demand and NEL

| | Peak Demand | | NEL Demand | |
|---|---|---|---|---|
| | Summer (MW) | Percentage Change | Summer (GWh) | Percentage Change |
| 2002 | 1,928 | | 9,027 | |
| 2003 | 2,207 | 14.4 | 9,620 | 6.6 |
| 2004 | 2,295 | 4.0 | 9,972 | 3.7 |
| 2005 | 2,455 | 10.2 | 10,669 | 7.0 |
| 2006 (1) | 2,613 | 11.9 | | |
| Average Annual Growth Rate | 7.9 % | | 5.7 % | |
| Average of Annual Percentage Changes | | 10.1 | | 6.5 |

(1)Actual 2006 NEL is not available at the time this Power Supply Study was performed.

Brazos Electric's historical net energy for load (NEL) requirements are also shown in Table 3-1. NEL is the net energy required for Brazos Electric's customers and does not include off-system sales. From 2002 through 2005, total NEL requirements increased from 9,027 gigawatt-hour (GWh) to 10,669 GWh at an annual average growth rate of 5.7 percent. Figure 3-2 shows NEL as well as forecast NEL through 2022.

### *3.1.3 Base Case Peak Demand and NEL Forecasts*

The results of Brazos Electric peak demand forecasts are shown in Table 3-2. Table 3-2 indicates that the total peak demand in 2007 is projected to be 2,795 MW while the 2022 peak demand is projected to be 6,823 MW. During the forecast period through 2022, total peak demand is forecast to increase at an average annual growth rate of 6.1 percent, which is less than the recent actual growth rate. Figure 3-1 shows the forecasted peak demand for Brazos Electric along with the historical peak demand.

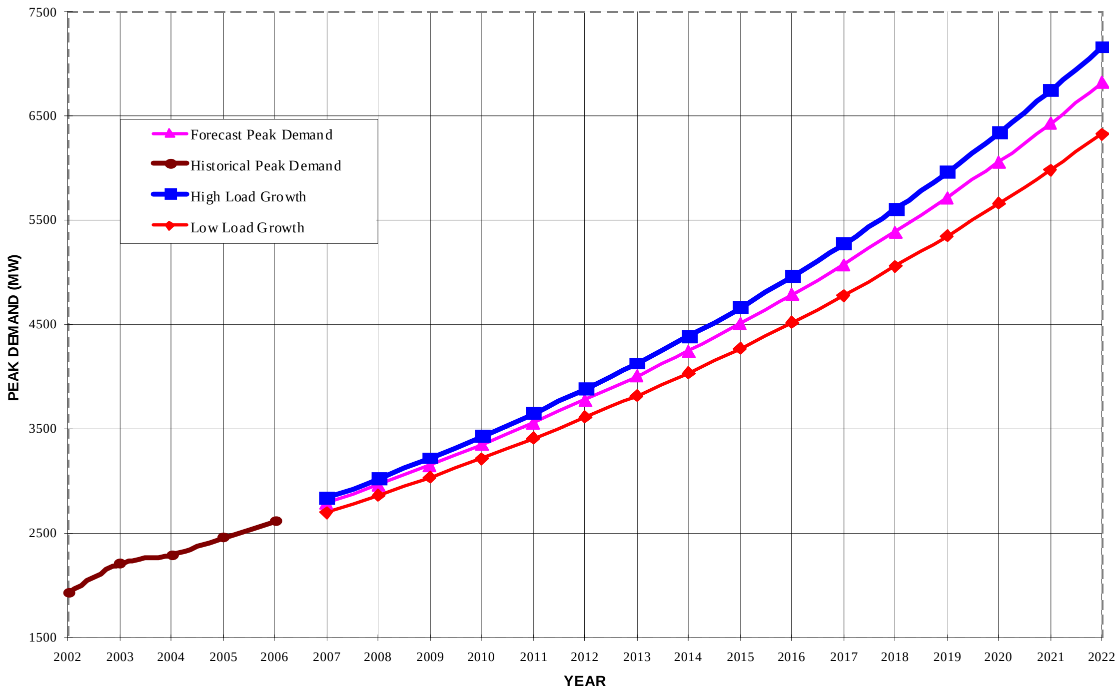


Figure 3-1
Historical and Peak Demand Forecast

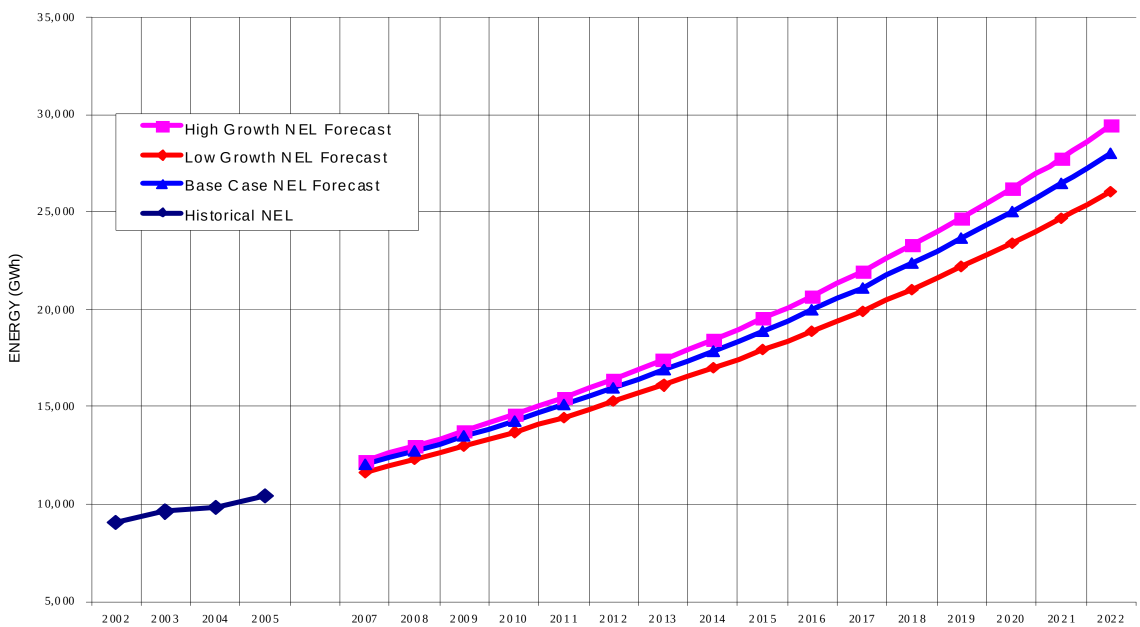


Figure 3-2
Historical and Forecast NEL

Table 3-2
Brazos Electric Base Case Peak Demand and NEL Forecast

| Year | Peak Demand (MW) | NEL (GWh) |
|---|---|---|
| 2007 | 2,795 | 12,039 |
| 2008 | 2,970 | 12,738 |
| 2009 | 3,155 | 13,476 |
| 2010 | 3,351 | 14,261 |
| 2011 | 3,560 | 15,094 |
| 2012 | 3,781 | 15,976 |
| 2013 | 4,009 | 16,889 |
| 2014 | 4,253 | 17,859 |
| 2015 | 4,511 | 18,886 |
| 2016 | 4,786 | 19,977 |
| 2017 | 5,077 | 21,134 |
| 2018 | 5,387 | 22,359 |
| 2019 | 5,715 | 23,655 |
| 2020 | 6,063 | 25,029 |
| 2021 | 6,431 | 26,477 |
| 2022 | 6,823 | 28,014 |
| Average Annual Growth Rate (percent) | 6.1 | 5.8 |

Brazos Electric forecasts the NEL using similar methodology as used in developing the peak demand forecast. Table 3-2 presents the NEL forecast, which increases from 12,039 GWh in 2007 to 28,014 GWh in 2022 at an average annual growth rate of 5.8 percent, which is comparable to the recent actual growth rate. Figure 3-2 shows the forecasted NEL for Brazos Electric along with historical NEL.

### *3.1.4 High and Low Peak Demand and NEL Forecasts*

In addition to the base case forecast, Brazos Electric also developed a forecast that incorporates the potential impact of extreme temperatures, as well as that of a strong and weak economy, on the forecasted base case peak demand. For the high peak demand and NEL scenario, a forecast was developed for the combination of a strong economy and extreme high summer temperatures, while for the low peak demand and NEL scenario, the forecast was developed based on the combination of a weak economy and very low summer temperatures. The high and low growth forecasts are presented in Table 3-3.

Table 3-3
Brazos Electric High Growth and Low Growth Peak Demand and NEL Forecast

| Fiscal Year | High Growth Case[1] | | Low Growth Case[2] | |
|---|---|---|---|---|
| | Peak Demand (MW) | NEL (GWh) | Peak Demand (MW) | NEL (GWh) |
| 2007 | 2,839 | 12,243 | 2,702 | 11,655 |
| 2008 | 3,023 | 12,979 | 2,865 | 12,305 |
| 2009 | 3,217 | 13,758 | 3,036 | 12,987 |
| 2010 | 3,425 | 14,590 | 3,217 | 13,710 |
| 2011 | 3,646 | 15,474 | 3,409 | 14,473 |
| 2012 | 3,881 | 16,413 | 3,611 | 15,279 |
| 2013 | 4,125 | 17,389 | 3,819 | 16,108 |
| 2014 | 4,385 | 18,428 | 4,039 | 16,986 |
| 2015 | 4,662 | 19,532 | 4,272 | 17,913 |
| 2016 | 4,957 | 20,707 | 4,519 | 18,894 |
| 2017 | 5,271 | 21,954 | 4,781 | 19,930 |
| 2018 | 5,605 | 23,280 | 5,058 | 21,025 |
| 2019 | 5,960 | 24,686 | 5,350 | 22,179 |
| 2020 | 6,338 | 26,179 | 5,659 | 23,398 |
| 2021 | 6,738 | 27,756 | 5,984 | 24,678 |
| 2022 | 7,161 | 29,435 | 6,330 | 26,034 |
| Average Annual Growth Rate (percent) | 6.4 | 6.0 | 5.8 | 5.5 |

[1]Based on a high summer temperature and strong economy.
[2]Based on a low summer temperature and weak economy.

In the high load growth scenario, the total peak demand is forecast to increase at an average annual growth rate of 6.4 percent while NEL is expected to grow at an annual average rate of 6.0 percent. Table 3-3 indicates that the total peak demand and NEL are projected to be 2,655 MW and 12,243 GWh in 2007, respectively, while the 2022 peak demand and NEL are expected to be 7,161 MW and 29,435 GWh, respectively. Figures 3-1 and 3-2 show the high growth peak demand and NEL forecasts.

In the low load growth scenario, the total peak demand is forecast to increase at an average annual growth rate of 5.8 percent while NEL is expected to grow at an average annual rate of 5.5 percent. Table 3-3 indicates that the total peak demand in 2007 is projected to be 2,702 MW while the 2022 peak demand is expected to be 6,330 MW. Total NEL increases from 11,655 GWh in 2007 to 26,034 GWh in 2022. Figures 3-1 and 3-2 show the low growth for peak demand and NEL forecasts.

### *3.1.5 Load Forecast Summary*

Since 2001, Brazos Electric has experienced a significant increase in its peak load. This is primarily due to the concentrated growth in the Dallas area, just north of the city. Black & Veatch reviewed the load forecast developed by Brazos Electric. Figure 3-3 provides linear and multiple (logarithmic) regressions based on the historical data available and extrapolated the expected demand through 2022. These values were plotted on a graph and compared with the base forecast.

As can be seen from Figure 3-3, the forecast load is in between a liner and logarithmic regression trend lines, and tracks near both trend lines in the early years. Black & Veatch recommends that the load forecast be continually monitored and modified based on the historical data trends and new forecasts to avoid actual future demand falling short of or exceeding forecast demand.

## 3.2 Fuel Forecast

The fuel price forecast is a major component in Brazos Electric's evaluation of future resource plans. The prices of the fuels used in power generation are extremely volatile and are difficult to accurately forecast due to a variety of unforeseeable factors. As a result, high and low price sensitivities will be evaluated. Forecasts were developed for the years 2007 through 2035 for lignite coal, subbituminous PRB coal, natural gas, and fuel oil.

In developing fuel price forecasts, Brazos Electric utilizes the services of ACES. ACES provides monthly updates to its power price forecast. ACES utilizes NYMEX pricing for near term, dealer quotes as available for intermediate term, and its own forecasts for long-term price forecasts.

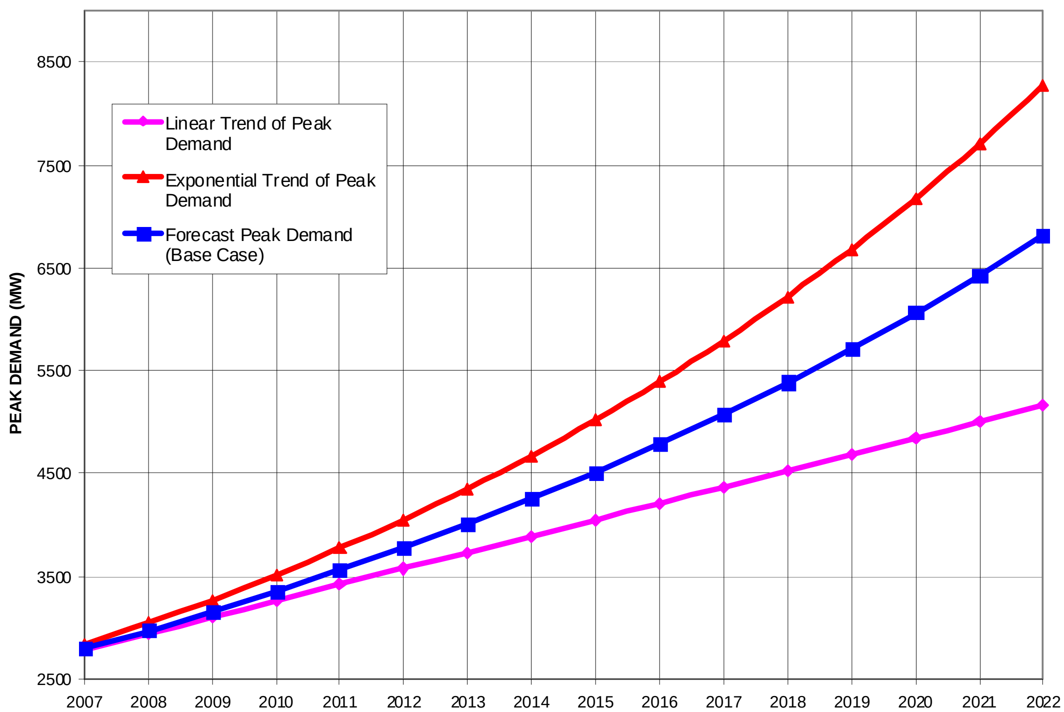


Figure 3-3
Comparison of Forecasted Capacity Demand

### *3.2.1 Fuel Forecast Methodology*

This subsection discusses the methodology, algorithms, and assumptions that were used to develop the base case fuel forecast prices for the years 2006 through 2035. The fuel price forecast developed by ACES for various fuel types was used by Brazos Electric to develop delivered fuel price forecasts for all fuels.

Brazos Electric owns and operates the Jack County, Johnson County, Miller, and North Texas gas fired generating plants all of which are described in Section 2.0. The Jack County plant consists of a 2x1 combined cycle plant with a net summer rating of 600 MW, including duct fired capability. The Johnson County plant consists of a 1x1 combined cycle plant with a combined net summer rating of 258 MW. The Miller plant consists of three conventional gas fired steam generating units, having a combined net summer capacity of 403 MW, and two simple cycle combustion turbine generating units with a combined capacity of 208 MW. The North Texas plant consists of two conventional gas fired steam generating units, with a combined net summer capacity of 36 MW. A third North Texas unit (39.5 MW net summer capacity) is currently not operating because of emission limitations.

Brazos Electric and WFEC are jointly constructing the Hugo 2 coal project, currently expected to come on-line in 2012. Hugo 2 will be a 750 MW supercritical pulverized coal unit that will utilize PRB coal. Brazos Electric will own a 393 MW share of the project with the remainder to be owned by WFEC, who will also operate the unit.

The forecast for coal includes prices for PRB coal and Gulf Lignite coal. PRB coal transportation costs were considered in developing the price forecast for PRB coal. However, Gulf Lignite coal, which is assumed to be the primary fuel for the CFB option, is considered to be delivered at the minemouth, and therefore, transportation costs were not considered in developing the price forecast.

The forecast for natural gas includes the cost of the commodity itself and the cost of variable transportation. The variable fuel rate is a blended rate based on the terms and conditions of current natural gas transportation contracts. The fuel price does not include the cost of fixed transportation or the capital cost of pipeline facilities to interconnect with the natural gas interstate pipeline network.

Ultra-low sulfur diesel is currently used as backup fuel in the existing plants. The new generating alternatives considered as part of this study will not use fuel oil as a primary fuel but may be capable of using fuel oil as a backup fuel.

### *3.2.2 Summary of Existing Natural Gas Contracts*

Currently, Brazos Electric has purchase agreements for a total of 144,000 MBtu/day of firm natural gas supply and transportation. Brazos Electric has an agreement to purchase 34,000 MBtu/day of firm gas supply from Devon Gas Services. Brazos Electric has agreements for 40,000 MBtu/day of firm natural gas transportation from Energy Transfer Fuel, 60,000 MBtu/day from Atmos Pipeline, Texas, and 10,000 MBtu/day of firm natural gas transportation with Natural Gas Pipeline Company of America. The rest of the firm natural gas is purchased from various other companies.

### *3.2.3 Base Case Fuel Forecast*

The fuel prices, developed by ACES, reflect price forecasts for the types of fuel being used by existing and proposed generating facilities. The fuel price forecasts will be used in the economic evaluations to determine the cost of future operations at existing plants and to evaluate the cost of operating new generating facilities that are being considered as part of this study. The proposed CFB alternative considered will use the Gulf Lignite coal price forecast, while the 500 MW supercritical PC plant and the IGCC new generation alternative will use the subbituminous PRB coal price forecast. Other existing and new generation alternatives will use the natural gas and fuel oil price forecasts.

***3.2.3.1 Coal.*** Coal is a complex combination of organic and inorganic mineral matter formed over the course of thousands of years from fallen layers of vegetation. Bituminous coal is the highest ranking type of coal of those commonly used in power generation. It has a typical moisture content of less than 20 percent. Lignite coal is the lowest rank of coal. It is almost exclusively used as fuel in steam-electric power generation. It has moisture content as high as 45 percent. Subbituminous coal has properties between bituminous and lignite. Its moisture content ranges from 20 to 30 percent. The primary source of subbituminous coal is the Powder River Basin in Wyoming. Figure 3-4 shows the PRB base price and the delivered prices for the North and South Texas sites.

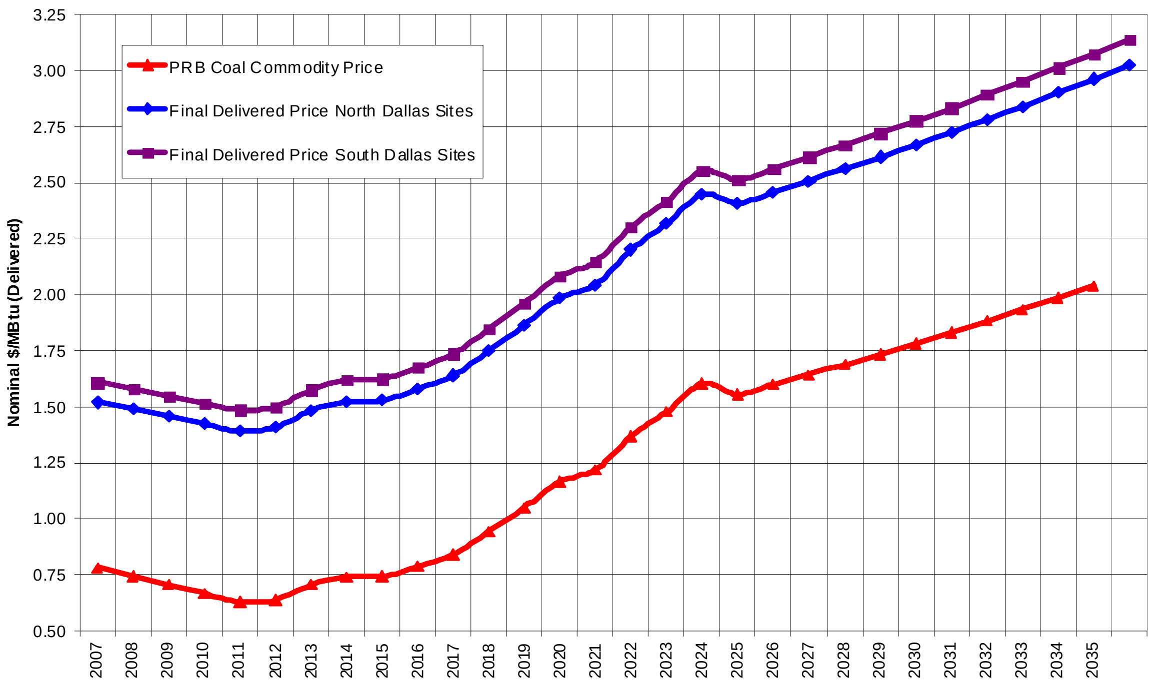


Figure 3-4
PRB Coal Base Price and Delivered Price Forecast

The delivered PRB price forecasts were developed by adding the rail transportation costs component to the PRB price forecast provided by ACES. The transportation cost forecast for Brazos Electric for the entire study period (2007 to 2035) is shown in Table 3-4. Gulf Lignite coal prices are minemouth prices, and therefore, transportation costs are not considered in the price forecast. Tables 3-5 and 3-6 present the base case forecast for PRB coal and Gulf Lignite coal, respectively, for the study period. Figure 3-5 shows the price forecast for Gulf Lignite coal.

Table 3-4
Brazos Electric Rail Transport Cost Forecast for PRB Coal
($/ton)

| Year | North Sites | South Sites |
|---|---|---|
| 2007 | 14.32 | 16.07 |
| 2008 | 14.44 | 16.20 |
| 2009 | 14.55 | 16.33 |
| 2010 | 14.67 | 16.46 |
| 2011 | 14.79 | 16.59 |
| 2012 | 14.91 | 16.72 |
| 2013 | 15.03 | 16.86 |
| 2014 | 15.15 | 16.99 |
| 2015 | 15.27 | 17.13 |
| 2016 | 15.39 | 17.26 |
| 2017 | 15.51 | 17.40 |
| 2018 | 15.64 | 17.54 |
| 2019 | 15.76 | 17.68 |
| 2020 | 15.89 | 17.82 |
| 2021 | 16.01 | 17.97 |
| 2022 | 16.14 | 18.11 |
| 2023 | 16.27 | 18.25 |
| 2024 | 16.40 | 18.40 |
| 2025 | 16.53 | 18.55 |
| 2026 | 16.67 | 18.70 |
| 2027 | 16.80 | 18.85 |
| 2028 | 16.93 | 19.00 |
| 2029 | 17.07 | 19.15 |
| 2030 | 17.21 | 19.30 |
| 2031 | 17.34 | 19.46 |
| 2032 | 17.48 | 19.61 |
| 2033 | 17.62 | 19.77 |
| 2034 | 17.76 | 19.93 |
| 2035 | 17.90 | 20.09 |

| Table 3-5<br>Brazos Electric Base Case Price Forecast for PRB Coal<br>(Nominal $/MBtu ) | | | | | |
|---|---|---|---|---|---|
| | PRB Coal Price | Calculated Transportation Cost Component | | Final Delivered Price | |
| | (Annual Average) | (Annual Average) | | (Annual Average) | |
| Year | | North Sites | South Sites | North Sites | South Sites |
| 2007 | 0.78 | 0.74 | 0.83 | 1.52 | 1.61 |
| 2008 | 0.74 | 0.74 | 0.83 | 1.48 | 1.57 |
| 2009 | 0.70 | 0.75 | 0.84 | 1.45 | 1.54 |
| 2010 | 0.67 | 0.76 | 0.85 | 1.43 | 1.52 |
| 2011 | 0.63 | 0.76 | 0.86 | 1.39 | 1.49 |
| 2012 | 0.64 | 0.77 | 0.86 | 1.41 | 1.50 |
| 2013 | 0.71 | 0.77 | 0.87 | 1.48 | 1.58 |
| 2014 | 0.74 | 0.78 | 0.88 | 1.52 | 1.62 |
| 2015 | 0.74 | 0.79 | 0.88 | 1.53 | 1.62 |
| 2016 | 0.78 | 0.79 | 0.89 | 1.57 | 1.67 |
| 2017 | 0.84 | 0.80 | 0.90 | 1.64 | 1.74 |
| 2018 | 0.94 | 0.81 | 0.90 | 1.75 | 1.84 |
| 2019 | 1.05 | 0.81 | 0.91 | 1.86 | 1.96 |
| 2020 | 1.16 | 0.82 | 0.92 | 1.98 | 2.08 |
| 2021 | 1.22 | 0.83 | 0.93 | 2.05 | 2.15 |
| 2022 | 1.37 | 0.83 | 0.93 | 2.20 | 2.30 |
| 2023 | 1.48 | 0.84 | 0.94 | 2.32 | 2.42 |
| 2024 | 1.60 | 0.85 | 0.95 | 2.45 | 2.55 |
| 2025 | 1.56 | 0.85 | 0.96 | 2.41 | 2.52 |
| 2026 | 1.60 | 0.86 | 0.96 | 2.46 | 2.56 |
| 2027 | 1.64 | 0.87 | 0.97 | 2.51 | 2.61 |
| 2028 | 1.69 | 0.87 | 0.98 | 2.56 | 2.67 |
| 2029 | 1.73 | 0.88 | 0.99 | 2.61 | 2.72 |
| 2030 | 1.78 | 0.89 | 0.99 | 2.67 | 2.77 |
| 2031 | 1.83 | 0.89 | 1.00 | 2.72 | 2.83 |
| 2032 | 1.88 | 0.90 | 1.01 | 2.78 | 2.89 |
| 2033 | 1.93 | 0.91 | 1.02 | 2.84 | 2.95 |
| 2034 | 1.99 | 0.92 | 1.03 | 2.91 | 3.02 |
| 2035 | 2.04 | 0.92 | 1.04 | 2.96 | 3.08 |

Table 3-6
Brazos Electric Base Case Price Forecast for Gulf Lignite Coal
(Nominal $/MBtu)

| Year | Lignite Coal Price (Annual Average) |
|---|---|
| 2007 | 1.54 |
| 2008 | 1.51 |
| 2009 | 1.47 |
| 2010 | 1.37 |
| 2011 | 1.43 |
| 2012 | 1.48 |
| 2013 | 1.43 |
| 2014 | 1.39 |
| 2015 | 1.38 |
| 2016 | 1.47 |
| 2017 | 1.50 |
| 2018 | 1.55 |
| 2019 | 1.66 |
| 2020 | 1.72 |
| 2021 | 1.79 |
| 2022 | 1.93 |
| 2023 | 2.02 |
| 2024 | 2.02 |
| 2025 | 1.89 |
| 2026 | 1.94 |
| 2027 | 1.99 |
| 2028 | 2.05 |
| 2029 | 2.10 |
| 2030 | 2.16 |
| 2031 | 2.22 |
| 2032 | 2.28 |
| 2033 | 2.34 |
| 2034 | 2.41 |
| 2035 | 2.48 |

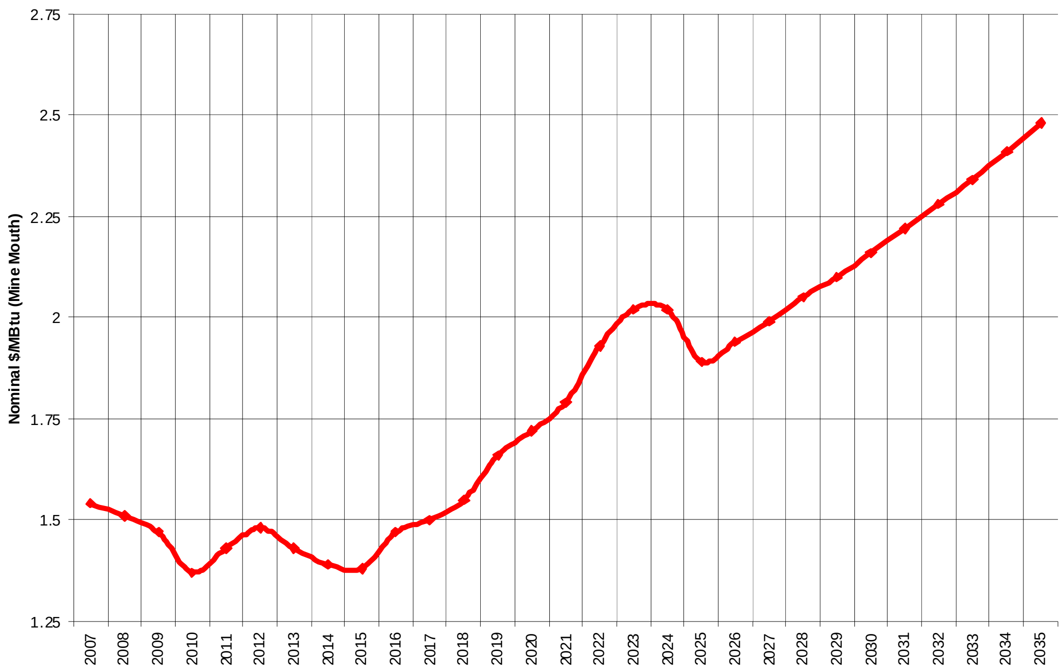


Figure 3-5
Gulf Lignite Coal Price Forecast

***3.2.3.2 Natural Gas.*** Natural gas is a clean burning, combustible mixture of hydrocarbon gases, primarily composed of methane. Methane is principally formed from the decomposition of organic waste and mineral fuel extraction. Methane can be extracted from mineral deposits. Natural gas can be liquefied for shipment as liquefied natural gas (LNG) and then regasified for injection into pipeline systems.

Natural gas is the primary fuel for Brazos Electric's existing, as well as new, simple cycle and combined cycle plants being evaluated as generating alternatives. As such, the price of natural gas is a major factor in Brazos Electric's capacity planning efforts. ACES provided Brazos Electric with the monthly price forecast for every month in the study period. The monthly price forecasts are shown on Figure 3-6. The average annual price for natural gas was calculated from this monthly price forecast and is presented in Table 3-10. It is also shown on Figure 3-6.

***3.2.3.3 Fuel Oil.*** Fuel oil is a product derived during the refinement of crude oil. Brazos Electric's existing generating units burn No. 2 fuel oil (diesel) as the backup fuel for all simple and steam plants at the Miller and North Texas sites. ACES provided Brazos Electric with the monthly price forecast for every month in the study period. The monthly price forecasts are shown on Figure 3-7. The average annual price for fuel oil was calculated from this monthly price forecast and is presented in Table 3-7. It is also shown on Figure 3-7.

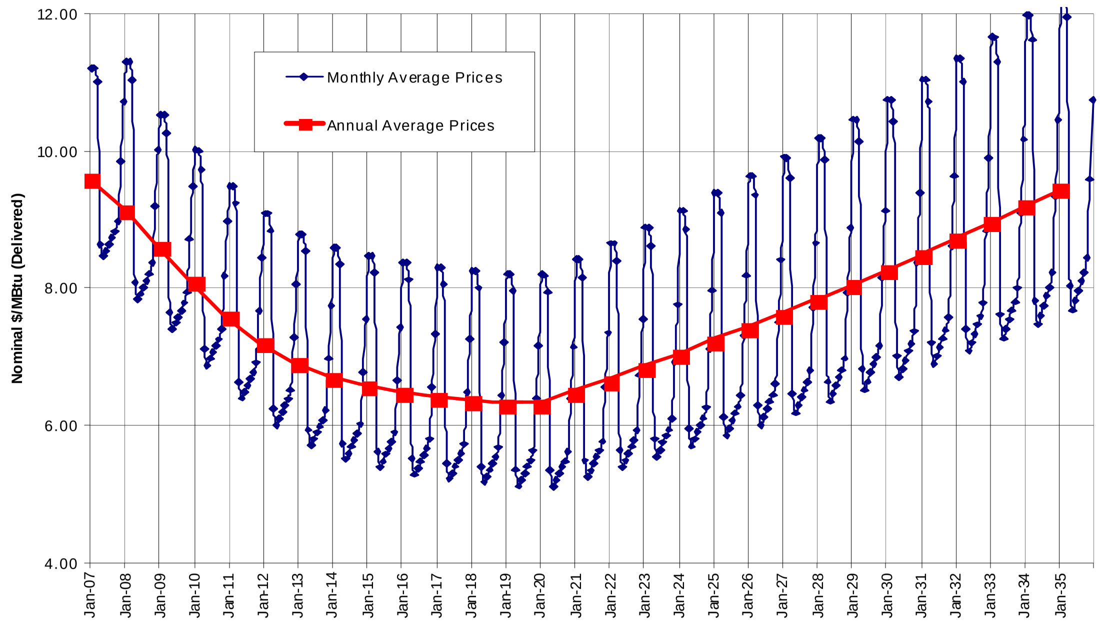


Figure 3-6
Natural Gas Price Forecast

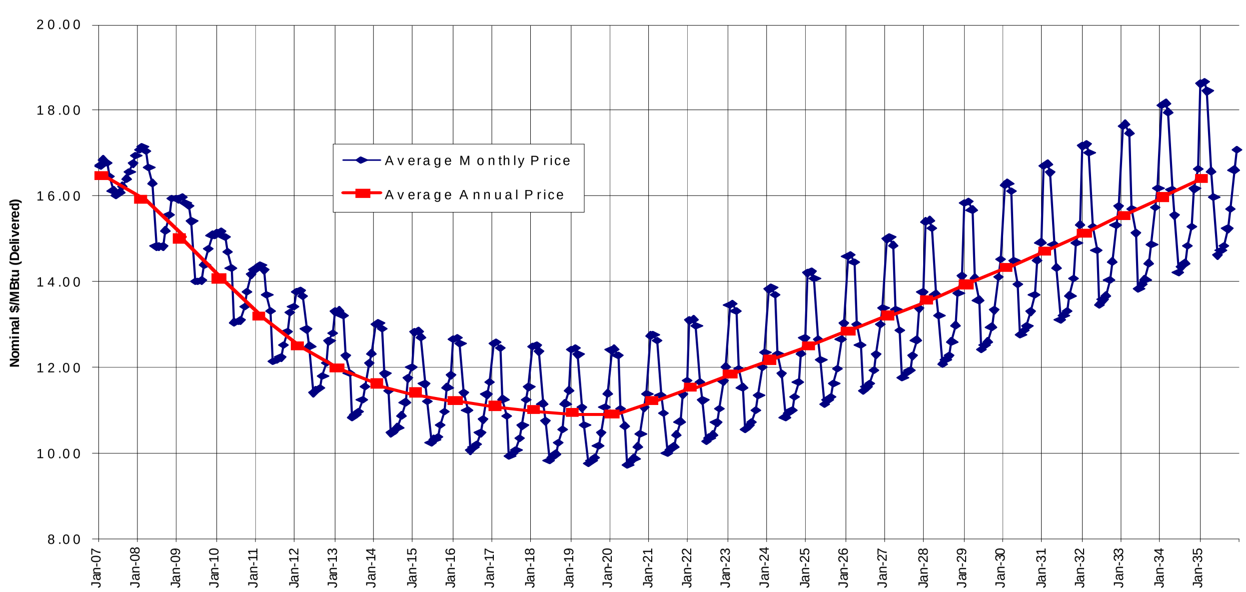


Figure 3-7
Ultra-Low Sulfur Diesel Price Forecast

Table 3-7
Brazos Electric Base Case Natural Gas and Fuel Oil Price Forecast
(Nominal $/MBtu Delivered)

| Year | Natural Gas (Annual Average) | Ultra-Low Sulfur Diesel (Annual Average) |
|---|---|---|
| 2007 | 9.56 | 16.49 |
| 2008 | 9.11 | 15.94 |
| 2009 | 8.59 | 15.02 |
| 2010 | 8.06 | 14.10 |
| 2011 | 7.56 | 13.22 |
| 2012 | 7.17 | 12.52 |
| 2013 | 6.87 | 11.99 |
| 2014 | 6.67 | 11.63 |
| 2015 | 6.55 | 11.42 |
| 2016 | 6.45 | 11.24 |
| 2017 | 6.38 | 11.12 |
| 2018 | 6.33 | 11.03 |
| 2019 | 6.29 | 10.95 |
| 2020 | 6.28 | 10.93 |
| 2021 | 6.45 | 11.23 |
| 2022 | 6.63 | 11.54 |
| 2023 | 6.81 | 11.86 |
| 2024 | 7.00 | 12.19 |
| 2025 | 7.19 | 12.52 |
| 2026 | 7.39 | 12.87 |
| 2027 | 7.59 | 13.22 |
| 2028 | 7.80 | 13.58 |
| 2029 | 8.01 | 13.96 |
| 2030 | 8.23 | 14.34 |
| 2031 | 8.46 | 14.74 |
| 2032 | 8.69 | 15.14 |
| 2033 | 8.93 | 15.56 |
| 2034 | 9.18 | 15.98 |
| 2035 | 9.43 | 16.42 |

### *3.2.4 High Case Fuel Forecasts*

A high case fuel price forecast was developed to address the uncertainty associated with the base case fuel price forecasts. The fuel price forecasts for the high case were developed by applying a fixed percentage increase from the delivered price projections developed for the base case. The forecast prices for coal were developed by increasing the average annual commodity fuel price and transportation cost projection in the base case by 25 percent. The forecast prices for natural gas and diesel oil were developed by increasing the average annual fuel price projection in the base case by 25 percent. Table 3-8 presents the high case forecasts for PRB coal and Gulf Lignite coal, while Table 3-9 presents the high case forecast for natural gas and fuel oil.

### *3.2.5 Low Case Fuel Forecasts*

A low case fuel price forecast was developed to address the uncertainty associated with the base case fuel forecasts. The fuel price forecasts for the low case were developed by applying a fixed percentage decrease from the delivered price projections developed for the base case. The prices for coal were developed by decreasing each average annual commodity fuel price and transportation cost projection in the base case by 25 percent. The price forecasts for natural gas and diesel oil were developed by decreasing each average annual fuel price projection in the base case by 25 percent. Table 3-10 presents the low case forecasts for PRB coal and Gulf Lignite coal, while Table 3-11 presents the low case forecasts for natural gas and fuel oil.

## 3.3 Emission Allowance Price Forecast

ACES provided a forecast of sulfur dioxide ($SO_2$) and nitrogen oxide ($NO_x$) allowance prices that corresponds to its base case fuel forecast. The $SO_2$ and $NO_x$ allowance price forecasts are presented in Table 3-14 for the base case fuel forecast.

### *3.3.1 Consideration of Emission Allowance Pricing in Economic Analysis*

The allowance price forecasts summarized in this section will influence the strategic capacity expansion planning efforts in the future. In determining a the most economic capacity expansion plan to satisfy future capacity requirements, it is prudent to add forecast emission allowance prices to the fuel price forecast for existing units, as well as potential capacity additions, or candidate units. The emission allowance price forecasts are presented in Table 3-12.

Table 3-8
Brazos Electric High Case Price Forecast for PRB and
Gulf Lignite Coal (Nominal $MBtu)

| Year | PRB Coal (North Sites) (Average Annual) | PRB Coal (South Sites) (Average Annual) | Lignite Coal (Average Annual) |
|---|---|---|---|
| 2007 | 1.72 | 1.81 | 1.93 |
| 2008 | 1.67 | 1.76 | 1.89 |
| 2009 | 1.63 | 1.72 | 1.84 |
| 2010 | 1.60 | 1.69 | 1.71 |
| 2011 | 1.55 | 1.65 | 1.79 |
| 2012 | 1.57 | 1.66 | 1.85 |
| 2013 | 1.66 | 1.76 | 1.79 |
| 2014 | 1.71 | 1.81 | 1.74 |
| 2015 | 1.72 | 1.81 | 1.73 |
| 2016 | 1.77 | 1.87 | 1.84 |
| 2017 | 1.85 | 1.95 | 1.88 |
| 2018 | 1.99 | 2.08 | 1.94 |
| 2019 | 2.12 | 2.22 | 2.08 |
| 2020 | 2.27 | 2.37 | 2.15 |
| 2021 | 2.36 | 2.46 | 2.24 |
| 2022 | 2.54 | 2.64 | 2.41 |
| 2023 | 2.69 | 2.79 | 2.53 |
| 2024 | 2.85 | 2.95 | 2.53 |
| 2025 | 2.80 | 2.91 | 2.36 |
| 2026 | 2.86 | 2.96 | 2.43 |
| 2027 | 2.92 | 3.02 | 2.49 |
| 2028 | 2.98 | 3.09 | 2.56 |
| 2029 | 3.04 | 3.15 | 2.63 |
| 2030 | 3.12 | 3.22 | 2.70 |
| 2031 | 3.18 | 3.29 | 2.78 |
| 2032 | 3.25 | 3.36 | 2.85 |
| 2033 | 3.32 | 3.43 | 2.93 |
| 2034 | 3.41 | 3.52 | 3.01 |
| 2035 | 3.47 | 3.59 | 3.10 |

Table 3-9
Brazos Electric High Case Natural Gas and Fuel Oil Price Forecast
(Nominal $/MBtu Delivered)

| Year | Natural Gas (Average Annual) | Ultra-Low Sulfur Diesel (Average Annual) |
|---|---|---|
| 2007 | 11.95 | 20.62 |
| 2008 | 11.39 | 19.93 |
| 2009 | 10.73 | 18.78 |
| 2010 | 10.08 | 17.62 |
| 2011 | 9.46 | 16.52 |
| 2012 | 8.97 | 15.65 |
| 2013 | 8.59 | 14.99 |
| 2014 | 8.34 | 14.54 |
| 2015 | 8.19 | 14.28 |
| 2016 | 8.07 | 14.06 |
| 2017 | 7.98 | 13.90 |
| 2018 | 7.92 | 13.79 |
| 2019 | 7.86 | 13.69 |
| 2020 | 7.85 | 13.67 |
| 2021 | 8.06 | 14.04 |
| 2022 | 8.28 | 14.43 |
| 2023 | 8.51 | 14.83 |
| 2024 | 8.75 | 15.23 |
| 2025 | 8.99 | 15.65 |
| 2026 | 9.23 | 16.08 |
| 2027 | 9.49 | 16.53 |
| 2028 | 9.75 | 16.98 |
| 2029 | 10.01 | 17.45 |
| 2030 | 10.29 | 17.93 |
| 2031 | 10.57 | 18.42 |
| 2032 | 10.86 | 18.93 |
| 2033 | 11.16 | 19.45 |
| 2034 | 11.47 | 19.98 |
| 2035 | 11.78 | 20.53 |

Table 3-10
Brazos Electric Low Case Price Forecast for PRB and Gulf Lignite Coal
(Nominal $/MBtu Delivered)

| Year | PRB Coal (South Sites) | PRB Coal (South Sites) | Lignite Coal |
|---|---|---|---|
| | (Average Annual) | (Average Annual | (Average Annual) |
| 2007 | 1.33 | 1.42 | 1.16 |
| 2008 | 1.30 | 1.39 | 1.13 |
| 2009 | 1.28 | 1.37 | 1.10 |
| 2010 | 1.26 | 1.35 | 1.03 |
| 2011 | 1.23 | 1.33 | 1.07 |
| 2012 | 1.25 | 1.34 | 1.11 |
| 2013 | 1.30 | 1.40 | 1.07 |
| 2014 | 1.34 | 1.44 | 1.04 |
| 2015 | 1.35 | 1.44 | 1.04 |
| 2016 | 1.38 | 1.48 | 1.10 |
| 2017 | 1.43 | 1.53 | 1.13 |
| 2018 | 1.52 | 1.61 | 1.16 |
| 2019 | 1.60 | 1.70 | 1.25 |
| 2020 | 1.69 | 1.79 | 1.29 |
| 2021 | 1.75 | 1.85 | 1.34 |
| 2022 | 1.86 | 1.96 | 1.45 |
| 2023 | 1.95 | 2.05 | 1.52 |
| 2024 | 2.05 | 2.15 | 1.52 |
| 2025 | 2.02 | 2.13 | 1.42 |
| 2026 | 2.06 | 2.16 | 1.46 |
| 2027 | 2.10 | 2.20 | 1.49 |
| 2028 | 2.14 | 2.25 | 1.54 |
| 2029 | 2.18 | 2.29 | 1.58 |
| 2030 | 2.23 | 2.33 | 1.62 |
| 2031 | 2.26 | 2.37 | 1.67 |
| 2032 | 2.31 | 2.42 | 1.71 |
| 2033 | 2.36 | 2.47 | 1.76 |
| 2034 | 2.41 | 2.52 | 1.81 |
| 2035 | 2.45 | 2.57 | 1.86 |

Table 3-11
Brazos Electric Low Case Natural Gas and Fuel Oil Price Forecast
(Nominal $/MBtu Delivered)

| Year | Natural Gas (Annual Average) | Ultra-Low Sulfur Diesel (Annual Average) |
|---|---|---|
| 2007 | 7.17 | 12.37 |
| 2008 | 6.84 | 11.96 |
| 2009 | 6.44 | 11.27 |
| 2010 | 6.05 | 10.57 |
| 2011 | 5.67 | 9.91 |
| 2012 | 5.38 | 9.39 |
| 2013 | 5.16 | 8.99 |
| 2014 | 5.01 | 8.73 |
| 2015 | 4.92 | 8.57 |
| 2016 | 4.84 | 8.43 |
| 2017 | 4.79 | 8.34 |
| 2018 | 4.75 | 8.27 |
| 2019 | 4.72 | 8.21 |
| 2020 | 4.71 | 8.20 |
| 2021 | 4.84 | 8.43 |
| 2022 | 4.97 | 8.66 |
| 2023 | 5.11 | 8.90 |
| 2024 | 5.25 | 9.14 |
| 2025 | 5.39 | 9.39 |
| 2026 | 5.54 | 9.65 |
| 2027 | 5.69 | 9.92 |
| 2028 | 5.85 | 10.19 |
| 2029 | 6.01 | 10.47 |
| 2030 | 6.17 | 10.76 |
| 2031 | 6.34 | 11.05 |
| 2032 | 6.52 | 11.36 |
| 2033 | 6.70 | 11.67 |
| 2034 | 6.88 | 11.99 |
| 2035 | 7.07 | 12.32 |

| Table 3-12<br>Emission Allowance Prices<br>(Nominal $/ton Removed) | | |
|---|---|---|
| Year | $SO_2$ Allowance Cost ($/ton) | Annual $NO_x$ Allowance Cost ($/ton) |
| 2007 | 665 | 1,500 |
| 2008 | 660 | 1,500 |
| 2009 | 640 | 1,818 |
| 2010 | 500 | 2,438 |
| 2011 | 390 | 2,545 |
| 2012 | 353 | 2,636 |
| 2013 | 786 | 2,717 |
| 2014 | 1,269 | 2,738 |
| 2015 | 1,323 | 3,698 |
| 2016 | 1,380 | 3,415 |
| 2017 | 1,522 | 3,930 |
| 2018 | 1,544 | 4,061 |
| 2019 | 1,624 | 4,207 |
| 2020 | 1,902 | 4,348 |
| 2021 | 1,972 | 4,414 |
| 2022 | 2,056 | 4,262 |
| 2023 | 2,115 | 4,671 |
| 2024 | 2,310 | 4,800 |
| 2025 | 2,269 | 4,940 |
| 2026 | 2,331 | 5,076 |
| 2027 | 2,396 | 5,216 |
| 2028 | 2,461 | 5,359 |
| 2029 | 2,529 | 5,506 |
| 2030 | 2,599 | 5,658 |
| 2031 | 2,670 | 5,813 |
| 2032 | 2,744 | 5,973 |
| 2033 | 2,819 | 6,137 |
| 2034 | 2,896 | 6,306 |
| 2035 | 2,976 | 6,480 |

### 3.3.2 High Emission Allowance Prices

The base emission allowance price forecasts provided by ACES are based on the assumption that the market for allowances in future regulatory programs will correlate with costs for adding emission control equipment. Historically, prices for emission allowances have been volatile, and this sensitivity case is based on assumed higher allowance prices.

In the high emission allowance price sensitivity case, the base case allowance prices were increased by 25 percent on an annual basis. Increasing allowance prices results in a higher cost adder for the fuels being burned in existing and candidate generating units. The increase in allowance prices results in a greater incentive to operate units with lower emission rates for electric generation, and also causes higher system costs relative to the base case economic analysis. Table 3-13 presents the high emission allowance prices.

### 3.3.3 Low Emission Allowance Prices

As mentioned above, the base emission allowance price forecasts provided by ACES are based on the assumption that the market for allowances in future regulatory programs will correlate with costs for adding emission control equipment. Historically, prices for emission allowances have been volatile, and this sensitivity case is based on assumed lower allowance prices.

In the low emission allowance price sensitivity case, the base case allowance prices were decreased by 25 percent on an annual basis. Decreasing allowance prices results in a lower cost adder for the fuels being burned in existing and candidate generating units. The decrease in allowance prices results in a lower incentive to operate units with lower emission rates for electric generation, and also causes lower system costs relative to the base case economic analysis. Table 3-14 presents the low emission allowance price forecast.

## 3.4 Economic Parameters

This section presents the economic parameters that were developed by Black & Veatch and assumed for Brazos Electric's Power Supply Study. The economic parameters were developed based on historical data and are consistently applied throughout the study.

Table 3-13
High Emission Allowance Prices
(Nominal $/ton Removed)

| Year | $SO_2$ Allowance Cost ($/ton) | Annual $NO_x$ Allowance Cost ($/ton) |
|---|---|---|
| 2007 | 831 | 1,875 |
| 2008 | 825 | 1,875 |
| 2009 | 800 | 2,272 |
| 2010 | 625 | 3,048 |
| 2011 | 487 | 3,181 |
| 2012 | 442 | 3,295 |
| 2013 | 982 | 3,397 |
| 2014 | 1,586 | 3,422 |
| 2015 | 1,654 | 4,622 |
| 2016 | 1,725 | 4,268 |
| 2017 | 1,903 | 4,913 |
| 2018 | 1,930 | 5,076 |
| 2019 | 2,030 | 5,258 |
| 2020 | 2,377 | 5,435 |
| 2021 | 2,465 | 5,518 |
| 2022 | 2,569 | 5,327 |
| 2023 | 2,644 | 5,839 |
| 2024 | 2,888 | 6,000 |
| 2025 | 2,836 | 6,175 |
| 2026 | 2,914 | 6,345 |
| 2027 | 2,994 | 6,519 |
| 2028 | 3,077 | 6,699 |
| 2029 | 3,161 | 6,883 |
| 2030 | 3,248 | 7,072 |
| 2031 | 3,338 | 7,267 |
| 2032 | 3,429 | 7,466 |
| 2033 | 3,524 | 7,672 |
| 2034 | 3,621 | 7,883 |
| 2035 | 3,720 | 8,100 |

Table 3-14
Low Emission Allowance Prices
(Nominal $/ton Removed)

| Year | $SO_2$ Allowance Cost ($/ton) | Annual $NO_x$ Allowance Cost ($/ton) |
|---|---|---|
| 2007 | 499 | 1,125 |
| 2008 | 495 | 1,125 |
| 2009 | 480 | 1,363 |
| 2010 | 375 | 1,829 |
| 2011 | 292 | 1,909 |
| 2012 | 265 | 1,977 |
| 2013 | 589 | 2,038 |
| 2014 | 951 | 2,053 |
| 2015 | 993 | 2,773 |
| 2016 | 1,035 | 2,561 |
| 2017 | 1,142 | 2,948 |
| 2018 | 1,158 | 3,045 |
| 2019 | 1,218 | 3,155 |
| 2020 | 1,426 | 3,261 |
| 2021 | 1,479 | 3,311 |
| 2022 | 1,542 | 3,196 |
| 2023 | 1,587 | 3,503 |
| 2024 | 1,733 | 3,600 |
| 2025 | 1,702 | 3,705 |
| 2026 | 1,749 | 3,807 |
| 2027 | 1,797 | 3,912 |
| 2028 | 1,846 | 4,019 |
| 2029 | 1,897 | 4,130 |
| 2030 | 1,949 | 4,243 |
| 2031 | 2,003 | 4,360 |
| 2032 | 2,058 | 4,480 |
| 2033 | 2,114 | 4,603 |
| 2034 | 2,172 | 4,730 |
| 2035 | 2,232 | 4,860 |

### *3.4.1 Inflation and Escalation Rates*

Table 3-15 presents the assumed general inflation rate, construction cost escalation rate, and fixed and nonfuel variable O&M escalation rates.

Table 3-15
Assumed Inflation and Escalation Rates

| Component | Annual Rate (percent) |
|---|---|
| General Inflation | 2.5 |
| Construction Cost Escalation | 2.5 |
| Fixed O&M Escalation | 2.5 |
| Nonfuel Variable O&M Escalation | 2.5 |

### *3.4.2 Debt Interest Rate*

The debt interest rate assumed for 30 year debt is 6.0 percent.

### *3.4.3 Present Worth Discount Rate*

The present worth discount rate was assumed to be equal to the debt interest rate of 6.0 percent.

### *3.4.4 Interest During Construction Rate*

The interest during construction (IDC) rate was assumed to be 6.0 percent.

### *3.4.5 Levelized Fixed Charge Rate*

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

The 30 year levelized FCR used in the economic evaluation is 8.44 percent. This FCR includes a 0 percent bond issuance fee, 0.78 percent payment in lieu of taxes, and a 0.42 percent annual insurance cost.

# 4.0 Capacity Requirements

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated available capacity. This section presents the development and analysis of the reliability criteria used by Brazos Electric.

Brazos has historically used a 12.5 percent reserve margin for RUS financing applications. For this Power Supply Study, Brazos Electric will use the 12.5 percent reserve margin for planning in the summer season. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. Brazos Electric plans to maintain the 12.5 percent reserve margin for firm load obligations.

## 4.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. One method is the reserve margin and another is the Loss of Load Probability (LOLP), which apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. Brazos Electric uses a reserve margin for planning purposes that accounts for partial requirements and other purchases that include reserves. These two methods are discussed below.

### *4.1.1 Reserve Margin*

The most commonly used deterministic method is the reserve margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand (After Interruptible Load)}}{\text{System Firm Peak Demand (After Interruptible Load)}}$$

With this equation, if either the net capacity or the firm peak demand deviates from predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. This formula calculates the reserve margin at a given point in time, but it does not indicate what the appropriate reserve margin is for a given system. Therefore, the appropriate reserve level must be determined by other means.

### *4.1.2 Loss of Load Probability*

The second commonly used method of calculating the reliability of a utility system is the LOLP. This method is advantageous in that it can result in a measure of how much capacity (and reserves) are needed to meet a target level of reliability (typically, an LOLP criterion of no more than 1 day in 10 years is used). Brazos Electric will continue to utilize the reserve margin since doing so has allowed Brazos Electric to adequately meet both criteria thus far.

## 4.2 Reliability Need

To determine Brazos Electric's need for power, a forecast of system peak demand was developed. The forecast of system peak demand was developed through 2022 and is discussed in Section 3.1. Although the Power Supply Study is for the period 2007 through 2035, the system demand is assumed to remain constant from 2023 until the end of the study period. Available net system capacity was also considered for the 2007 through 2035 period, and includes consideration of existing generation resources, existing system purchases, firm capacity additions, and firm retirements.

Brazos Electric and WFEC are jointly developing Hugo Unit 2. Hugo 2 is planned to be a 786 MW supercritical pulverized coal unit that will burn PRB coal. The unit is currently scheduled for commercial operation in 2012, and Brazos Electric will own a 393 MW share of the unit.

Brazos Electric purchases 195.5 MW of baseload lignite fueled generating capacity from San Miguel Electric Cooperative, Inc., and 54 MW of hydroelectric generating capacity from Southwestern Power Administration and Brazos River Authority under long-term contracts, which have been assumed to remain in effect for the duration of the study period (through 2035). Brazos Electric purchases 350 MW of capacity and energy under a 5-year (2006 through 2010) purchase power agreement with BP Energy Company. It is assumed that this 5 year contract would not be extended beyond 2010.

Historically, Brazos Electric has met a portion of its capacity requirements through various short-term capacity purchases, call options, forward contracts, and market purchases, and intends to continue to do so. However, Brazos Electric desires to maintain an appropriate balance between owned generating resources, power purchases, and market purchases. The forecast capacity requirements presented in Table 4-1 assume that Brazos Electric does not install any new generating resources beyond Hugo 2 nor does it extend the BP Energy Company purchase. Table 4-1 indicates that Brazos Electric's need for additional capacity to maintain the 12.5 percent reserve margin increases from 862 MW in 2007 to 5,528 MW in 2022 if no new capacity resources (beyond Hugo 2) are added to Brazos Electric's existing resources. The forecast capacity requirements presented in Table 4-1 will likely be satisfied through installation of new generating resources as well as short-term and long-term purchase power agreements, structured products, and market purchases.

Table 4-1
Current Summer Capacity Balance Forecast for Brazos Electric

| Calendar Year | Peak Demand (MW) | 12.5% Reserves (MW) | Total Peak + Reserves (MW) | Installed Capacity (MW) (1) | Purchased Capacity (MW) (2) | Capacity Sales (MW) | Total Available Capacity (MW) | Excess/ (Deficit) Capacity to Maintain 12.5% Reserve Margin (MW) |
|---|---|---|---|---|---|---|---|---|
| 2007 | 2,637 | 330 | 2,967 | 1,505 | 600 | 0 | 2,105 | (862) |
| 2008 | 2,970 | 371 | 3,341 | 1,505 | 600 | 0 | 2,105 | (1,237) |
| 2009 | 3,155 | 394 | 3,549 | 1,505 | 600 | 0 | 2,105 | (1,445) |
| 2010 | 3,351 | 419 | 3,770 | 1,505 | 600 | 0 | 2,105 | (1,665) |
| 2011 | 3,560 | 445 | 4,005 | 1,505 | 250 | 0 | 1,755 | (2,251) |
| 2012 | 3,781 | 473 | 4,254 | 1,898 | 250 | 0 | 2,148 | (2,106) |
| 2013 | 4,009 | 501 | 4,510 | 1,898 | 250 | 0 | 2,148 | (2,363) |
| 2014 | 4,252 | 532 | 4,784 | 1,898 | 250 | 0 | 2,148 | (2,636) |
| 2015 | 4,511 | 564 | 5,075 | 1,898 | 250 | 0 | 2,148 | (2,927) |
| 2016 | 4,786 | 598 | 5,384 | 1,898 | 250 | 0 | 2,148 | (3,237) |
| 2017 | 5,077 | 635 | 5,712 | 1,898 | 250 | 0 | 2,148 | (3,564) |
| 2018 | 5,387 | 673 | 6,060 | 1,898 | 250 | 0 | 2,148 | (3,913) |
| 2019 | 5,715 | 714 | 6,429 | 1,898 | 250 | 0 | 2,148 | (4,282) |
| 2020 | 6,063 | 758 | 6,821 | 1,898 | 250 | 0 | 2,148 | (4,673) |
| 2021 | 6,431 | 804 | 7,235 | 1,898 | 250 | 0 | 2,148 | (5,087) |
| 2022 | 6,823 | 853 | 7,676 | 1,898 | 250 | 0 | 2,148 | (5,528) |

(1)Does not include capacity from North Texas Unit 3, which is currently not operational due to emission limitations.

(2)Assumes expiration of the BP Energy Company purchase January 1, 2011, and includes the San Miguel Electric Cooperative and the Southwestern Power Administration and Brazos River Authority purchases through 2022.

# 5.0 Supply-Side Options

## 5.1 Generating Unit Assumptions

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry as well as a new unit, the General Electric (GE) LMS100 CT. The technologies considered include simple cycle CTs, CC configurations, CFB units, and PC units. In addition, indicative cost and performance estimates were developed for two emerging technologies: nuclear and IGCC.

Although the CTs and the CC alternatives discussed herein assume a specific manufacturer (GE) and specific models (i.e., aeroderivative and frame CTs), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made in order to provide indicative output and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

The capital cost estimates developed include both direct and indirect costs. An allowance for general owner's cost items, as summarized in Table 5-1, has been included in the cost estimates. Table 5-2 presents the matrix of generating unit alternatives that were considered for Brazos Electric. Some of the alternatives were assumed to be located at generic greenfield sites located in Johnson and Parker counties, while other alternatives were assumed to be located at existing sites at San Miguel and in Johnson and Jack counties. The cost estimates were developed for inside the fence costs based on the assumptions presented in the following subsections.

### *5.1.1 Conventional Alternatives Assumptions*

***5.1.1.1 General Capital Cost Assumptions.*** The following general assumptions were applied in developing the cost and performance estimates:

- Each site considered has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- Pile foundations are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).

Table 5-1
Possible Owner's Costs

**Project Development**

- Site selection study for greenfield sites
- Land purchase/options/rezoning for greenfield sites
- Transmission/gas pipeline right-of-way
- Road modifications/upgrades
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance

**Spare Parts and Plant Equipment**

- CT materials, gas compressors, supplies, and parts
- ST materials, supplies, and parts
- Boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishing and supplies

**Plant Startup/Construction Support**

- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals and reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchases
- Acceptance testing

**Owner's Contingency**

- Owner's uncertainty and costs pending final negotiation
    - Unidentified project scope increases
    - Unidentified project requirements
    - Costs pending final agreements (i.e., interconnection contract costs)

**Owner's Project Management**

- Preparation of bid documents and the selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

**Taxes/Advisory Fees/Legal**

- Taxes
    - Sales tax on taxable equipment outside the main power block
- Market and environmental consultants
- Owner's legal expenses
- Interconnect agreements
    - Contracts (procurement and construction)
    - Other contracts
    - Property

**Utility Interconnections**

- Natural gas service
    - Gas system upgrades
    - Electrical transmission
    - Water supply
    - Wastewater/sewer

**Financing (included in fixed charge rate, but not in direct capital cost)**

- Financial advisor, lender's legal, market analyst, and engineer
    - Loan administration and commitment fees
    - Debt service reserve fund

Note: Property taxes, insurance, and working capital are included in the fixed charge rate. Interest during construction will be calculated during the economic modeling.

| Table 5-2<br>Generating Unit Alternatives | |
|---|---|
| ID No. | Supply Alternative |
| 1 | Simple cycle GE LM6000 (two units) at a greenfield site |
| 2 | Simple cycle GE LMS100 at a greenfield site |
| 3 | Simple cycle GE 7FA with selective catalytic reduction (SCR) at a greenfield site |
| 4 | Simple cycle GE 7FA without SCR at a greenfield site |
| 5 | 1x1 GE 7FA CC at the Johnson County site |
| 6 | 2x1 GE 7FA CC at the Jack County site |
| 7 | 2x1 GE 7FA CC at a greenfield site |
| 8 | 500 MW supercritical PC unit at a greenfield site |
| 9 | 500 MW atmospheric CFB at the San Miguel site |
| 10 | 1x1 GE 7EA repowering of North Texas Unit 3 |

- CTs will be fueled with natural gas only. The LMS100 CT is assumed to have standard SCR. The LM6000 will have hot SCR. The 7FA CT will be evaluated with and without hot SCR. Except for the LMS100, the simple cycle units will not include a carbon monoxide (CO) catalyst but will have a spool piece for future installation.
- The LMS100 will utilize dry cooling. The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT™ option, which is also intercooling and will not utilize inlet cooling. The frame machines like the 7FA will utilize evaporative coolers for inlet cooling.
- CC plants will include SCR and dry-low $NO_x$ burners to reduce $NO_x$ emissions but will not include a CO catalyst; instead they will have a spool piece for future installation.
- All CC alternatives will utilize evaporative coolers for inlet cooling. Due to water constraints, the Jack County 2x1 addition will utilize an air-cooled condenser. All other CC units are assumed to use cooling towers.
- Standard sound enclosures will be included for noise reduction on the CTs.
- Natural gas pressure is assumed to be adequate for 7FA and 7EA alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative CTs. A regulating and metering station is assumed to be included within the owner's cost allowance for each alternative.
- Demineralized water will be provided via portable demineralizers for simple cycle alternatives, and using a demineralized water treatment system for the CC and solid fuel options.
- Field erected storage tanks include the following:
  - Service/fire water storage tank.
  - Demineralized water storage tank (3 full days' storage capacity).

#### *5.1.1.2 Fuel Assumptions.*

- Natural gas is approximately 90 percent methane with 0.2 grains of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb lower heating value (LHV).
- Coal for the supercritical PC and IGCC options is assumed to be PRB subbituminous coal and is assumed to have a heat content of 8,800 Btu/lb higher heating value (HHV), 0.4 percent sulfur, and 6.6 percent ash.
- Lignite coal for CFB alternative is assumed to have an approximate heat content of 4,838 Btu/lb, 2.0 percent sulfur, and 34.1 percent ash.

#### *5.1.1.3 Direct Cost Assumptions.*

- Total direct capital costs are expressed in 2006 dollars.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an engineering, procurement, and construction (EPC) contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation are included in owner's costs.
- Permitting and licensing are included in the owner's costs.

***5.1.1.4 Indirect Cost Assumptions.*** The following items are included in the capital cost estimate:

- General indirect costs, including all necessary services required for checkouts, testing, and commissioning.
- Insurance, including builder's risk and general liability.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Construction equipment.
- Construction office trailers, etc.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts which are assumed to be used during construction by the contractor.
- Interest during construction and financing fees will be calculated during the economic evaluation and are not included in the capital cost or owner's cost estimates.

***5.1.1.5 Meteorological Conditions.*** The average annual temperature and relative humidity (RH) of 68º F and 77 percent, respectively, will be used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 20º F (RH of 100 percent) and a summer temperature of 102º F (RH of

40.0 percent) will be used to develop seasonal performance estimates. An elevation of 950 feet will be assumed for generic alternatives. For existing sites, the following alternatives are assumed: Jack County at 950 feet, Johnson County at 850 feet, North Texas at 912 feet, and Miller at 895 feet.

***5.1.1.6 Performance Degradation.*** Power plant output and heat rate performance will degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance as compared to the unit's new and clean performance. The degradation which cannot be recovered is referred to herein as *nonrecoverable degradation*, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 5-3. These factors have been applied to the new and clean performance of the supply-side alternatives. The assumed average degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

Table 5-3
Nonrecoverable Degradation Factors

| | Degradation Factor | |
|---|---|---|
| Unit Description | Output (%) | Heat Rate (%) |
| GE LM6000 Simple Cycle | 3.2 | 1.75 |
| GE LMS100 Simple Cycle | 3.2 | 1.75 |
| GE 7FA Simple Cycle | 3.2 | 1.75 |
| GE 1x1 7EA CC | 2.7 | 1.50 |
| GE 1x1 7FA CC | 2.7 | 1.50 |
| GE 2x1 7FA CC | 2.7 | 1.50 |
| Supercritical PC and Lignite CFB | 0.0 | 1.50 |
| IGCC | 2.7 | 1.50 |

### *5.1.2 Generic Site Assumptions*

The following assumptions have been developed for generic sites:

- The plant will not be located on wetlands nor require any other mitigation.
- Service and fire water will be supplied from ground water via onsite wells.
- Potable water will be supplied from a local water utility.

- Wastewater disposal will utilize local sewer systems, except for the solid fuel options which are assumed to include treatment systems.
- Cooling water will be from surface or ground water resources. An allowance for pipeline costs is included as part of the owner's cost.
- An allowance for transmission lines is included as part of the owner's cost. An onsite switching station with a breaker position for each generator is included as part of the direct cost.

## 5.2 Generating Unit Options

This section presents a description of the generating options that were evaluated as potential sources of future capacity for Brazos Electric. In addition to a general description, each option consists of a summary of projected performance, emissions, capital cost, O&M costs, and other operating parameters.

### *5.2.1 Simple Cycle Combustion Turbine Options*

Combustion turbine generators (CTGs) are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle CT generates power by compressing ambient air and then heating the pressurized air to approximately 2,000º F or more by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical CT would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot (typically 900º F to 1,100º F) gases exiting the turbine exhaust. When the CT is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

CTs are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, CT output and efficiency decrease due to the lower density of the air. To lessen the impact of this negative characteristic, many CT based power plants now include inlet air-cooling systems to boost plant performance at higher ambient temperatures.

CT pollutant emission rates are typically higher on a part per million (ppm) basis at part-load operation than at full load. This characteristic has an effect on how much plant output can be decreased without exceeding pollutant emission limits. In general, CTs can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emissions levels within required limits.

Advantages of simple cycle CT projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of sizes. CT technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of CTs is that the variable cost per MWh of operation is generally high compared to other conventional technologies. As a result, simple cycle CTs are often the technology of choice for meeting peak loads in the power industry but are not usually economical for baseload or intermediate service.

Three different CT sizes were evaluated. The GE LM6000 has a nominal output in the range of 50 MW at International Organization for Standardization (ISO) conditions with the SPRINT design feature included, and the GE LMS100 has an approximate nominal output of 100 MW at ISO conditions. The GE 7FA has a nominal output of about 170 MW at ISO conditions.

Blocks of two LM6000s were evaluated. These two-unit blocks have roughly the same outputs at ISO conditions as a single LMS100. The LMS100 and the LM6000s were evaluated due to the lack of demonstrated reliability of the LMS100.

***5.2.1.1 General Electric LM6000 Combustion Turbine.*** The GE LM6000 was selected as a potential simple cycle alternative due to its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC), a fourteen-stage variable geometry high-pressure compressor (HPC), an annular combustor, a two-stage air-cooled high-pressure turbine (HPT), a five-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the low-pressure rotor. The HPC and HPT are assembled on the other shaft, forming the high-pressure rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct-coupling to 3,600 revolutions per minute (rpm) generators for 60 hertz (Hz) power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold," end of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- Five (5) million operating hours.
- More than 450 turbines sold.
- 97.8 percent documented availability.

- LM6000 SPRINT spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate will be based on utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 5-4 presents the operating characteristics of the LM6000 SPRINT CT at a winter temperature of 20º F (RH of 100.0 percent) and a summer temperature of 102º F (RH of 40.0 percent), and annual average temperature conditions (68º F with an RH of 77.0 percent). High temperature SCR will be used to control $NO_x$ to 5 parts per million volumetric dry (ppmvd) while operating on natural gas. Table 5-5 presents estimated emissions for the LM6000.

Table 5-4
GE LM6000 SPRINT Combustion Turbine Characteristics

| Ambient Condition | Net Capacity (MW)(1) | Net Plant Heat Rate (Btu/kWh, HHV)(1, 2) |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 92.4 | 9,636 |
| Summer (102º F and 40% RH) (Full Load) | 67.9 | 10,472 |
| Average (68º F and 77% RH) (Full Load) | 87.4 | 9,895 |
| Average (68º F and 77% RH) (75% Load) | 65.4 | 10,602 |
| Average (68º F and 77% RH) (50% Load) | 43.4 | 12,374 |
| Average (68º F and 77% RH) (Minimum Load - Unit) | 21.7 | 12,374 |

(1)Net capacity and full load net plant heat rate include degradation factors, and performance is preliminary.

(2)Heat rate assumes operation on natural gas.

***5.2.1.2 General Electric LMS100 Combustion Turbine.*** The GE LMS100 was selected because of its high efficiency and large output range. The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability.

| Table 5-5<br>GE LM6000 PC SPRINT Estimated Emissions[1] | |
|---|---|
| Emission Type | Natural Gas |
| $NO_x$, ppmvd at 15% $O_2$ | 5 |
| $NO_x$, lb/MBtu (HHV) | 0.0181 |
| $SO_2$, lb/MBtu (HHV) | 0.0006 |
| Hg, lb/MBtu (HHV) | NA |
| $CO_2$, lb/MBtu (HHV) | 116.5 |
| CO, ppmvd at 15% $O_2$ | 17 |
| CO, lb/MBtu (HHV) | 0.0371 |
| [1]Emissions are at full load at 68º F and include the effect of SCR. | |

The LMS100 is a new GE unit and has a disadvantage of not being commercially proven, like the LM6000. The first LMS100 unit, however, entered commercial service in early July 2006. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

Even though its front compressor is from a frame machine, the LMS100 is considered aeroderivative, and shares many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle turbines at full power.

There are two main differences between the LM6000 and the LMS100. The former uses the SPRINT intercooling system to cool the compressor with a micromist of water, while the latter cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has an HPT and a power turbine, the LMS100 has an additional intermediate-pressure turbine to increase the output efficiency. For evaluation purposes it is assumed that the LMS100 will utilize dry cooling.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air which is then compressed in a second compressor to a high pressure. The compressed air is then heated with combusted fuel, then used to drive the two-stage intermediate/high pressure turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800º F which allows the use of a standard SCR system for $NO_x$ control. Table 5-6 presents the operating characteristics of the LMS100 CT at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F.

Standard SCR will be used to control $NO_x$ to 5 ppmvd while operating on natural gas. Table 5-7 presents estimated emissions for the LMS100.

***5.2.1.3 General Electric 7FA Combustion Turbine.*** The GE 7FA CT, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F-Class gas turbines, enabling these machines to attain higher firing temperatures (2,400º F) than previous generating units.

The GE 7FA CTs have an eighteen-stage compressor and a three-stage turbine, and feature cold-end drive and axial exhaust which is beneficial for CC arrangements. Net operating efficiencies of 56 percent can be achieved by the GE 7FA CT in CC mode. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

The GE 7FA CT has also exhibited outstanding environmental characteristics. Due to the higher specific output of these machines, smaller amounts of $NO_x$ and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated millions of operating hours using dry-low $NO_x$ burners. It has been assumed that the 7FA will be fueled with natural gas only and will utilize evaporative cooling.

Since the GE 7FA CT has exhibited greater environmental standards with reduced $NO_x$ emissions, this unit was evaluated with and without the use of SCR. The performance of the unit would vary under these two assumptions. Table 5-8 presents the operating characteristics of the GE 7FA CT at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-9 shows the performance characteristics when no SCR is utilized. When equipped with SCR, the 7FA will utilize dry-low $NO_x$ combustors and hot SCR to control $NO_x$ to 2 ppmvd on natural gas. Table 5-10 presents estimated emissions for the 7FA with the use of SCR. Table 5-11 presents estimated emissions for the 7FA without the use of SCR.

Table 5-6
GE LMS100 Combustion Turbine Characteristics

| Ambient Condition | Net Capacity (MW)[1] | Net Plant Heat Rate (Btu/kWh, HHV)[1, 2] |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 97.8 | 8,844 |
| Summer (102º F and 40% RH) (Full Load) | 77.6 | 9,379 |
| Average (68º F and 77% RH) (Full Load) | 95.6 | 9,051 |
| Average (68º F and 77% RH) (75% Load) | 71.6 | 9,405 |
| Average (68º F and 77% RH) (50% Load) | 47.5 | 10,332 |
| Average (68º F and 77% RH) (Minimum Load – 50%) | 47.5 | 10,332 |

(1)Net capacity and full load net plant heat rate include degradation factors, and performance is preliminary. No evaporative cooling is installed on this option.
(2)Heat rate assumes operation on natural gas.

Table 5-7
GE LMS100 Estimated Emissions[1]

| Emission Type | Natural Gas |
|---|---|
| $NO_x$, ppmvd at 15% $O_2$ | 5 |
| $NO_x$, lb/MBtu (HHV) | 0.0182 |
| $SO_2$, lb/MBtu (HHV) | 0.0006 |
| Hg, lb/MBtu (HHV) | NA |
| $CO_2$, lb/MBtu (HHV) | 114.8 |
| CO, ppmvd at 15% $O_2$ | 14.2 |
| CO, lb/MBtu (HHV) | 0.0314 |
| $PM_{10}$ (Front half catch), lb/MBtu (HHV) | 0.0042 |
| PM (Front and back half catch), lb/MBtu (HHV) | 0.0076 |

(1)Emissions are at full load at 68º F and include the effects of SCR and CO catalyst.

Table 5-8
GE 7FA Combustion Turbine Characteristics with SCR

| Ambient Condition | Net Capacity (MW)[1] | Net Plant Heat Rate (Btu/kWh, HHV)[1, 2] |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 172.1 | 10,586 |
| Summer (102º F and 40% RH) (Full Load) | 144.5 | 11,060 |
| Average (68º F and 77% RH) (Full Load) | 154.7 | 10,843 |
| Average (68º F and 77% RH) (75% Load) | 115.9 | 11,828 |
| Average (68º F and 77% RH) (50% Load) | 76.9 | 14,246 |
| Average (68º F and 77% RH) (Minimum Load – 50%) | 76.9 | 14,246 |

(1)Net capacity and full load net plant heat rate include degradation factors, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table 5-9
GE 7FA Combustion Turbine Characteristics without SCR

| Ambient Condition | Net Capacity (MW)[1] | Net Plant Heat Rate (Btu/kWh, HHV)[1, 2] |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 172.6 | 10,557 |
| Summer (102º F and 40% RH) (Full Load) | 145.5 | 10,981 |
| Average (68º F and 77% RH) (Full Load) | 155.9 | 10,775 |
| Average (68º F and 77% RH) (75% Load) | 116.6 | 11,736 |
| Average (68º F and 77% RH) (50% Load) | 77.5 | 14,155 |
| Average (68º F and 77% RH) (Minimum Load – 50%) | 77.5 | 14,155 |

(1)Net capacity and full load net plant heat rate include degradation factors, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table 5-10
GE 7FA Estimated Emissions(1)

| Emission Type | Natural Gas |
|---|---|
| $NO_x$, ppmvd at 15% $O_2$ | 2 |
| $NO_x$, lb/MBtu (HHV) | 0.0073 |
| $SO_2$, lb/MBtu (HHV) | 0.0006 |
| Hg, lb/MBtu (HHV) | NA |
| $CO_2$, lb/MBtu (HHV) | 114.8 |
| CO, ppmvd at 15% $O_2$ | 7.5 |
| CO, lb/MBtu (HHV) | 0.0164 |

(1)Emissions are at full load at 68º F and include the effects of hot SCR.

Table 5-11
GE 7FA Estimated $NO_x$ Emissions(1)
(Without SCR)

| Emission Type | Natural Gas |
|---|---|
| $NO_x$, ppmvd at 15% $O_2$ | 9 |
| $NO_x$, lb/MBtu (HHV) | 0.0328 |

(1)Emissions are at full load at 68º F and do not include the effects of hot SCR.

### 5.2.2 Combined Cycle Options

CC power plants use one or more CTGs and a steam turbine generator (STG) to produce energy. CC power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. High-pressure steam is produced when the hot exhaust gas from the CT is passed through a heat recovery steam generator (HRSG). The high-pressure steam is then expanded through an ST which spins an electric generator. It is assumed that moderate duct firing will be used in all CC options to maintain full load on STs at all ambient conditions.

CC configurations have several advantages over simple cycle CTs. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of CCs relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements due to added plant complexity.

CC power plants were the generation technology of choice for most baseload and intermediate service plants constructed by the domestic power industry in the 1995 to 2003 time frame due to their high efficiency, relatively short construction period, and relatively modest natural gas prices.

***5.2.2.1 7EA Combined Cycle Repowering Option.*** In the 1x1 CC, a nonreheat HRSG and a STG are installed with a GE 7EA CT to form the CC configuration. The CC will be natural gas fired and will include evaporative cooling on the CT. The existing cooling system and North Texas Unit 3 ST will be reused. In the HRSG, the heat energy in the exhaust flow of the gas turbine is used to produce steam to drive the STG. Changing the GE 7EA simple cycle to CC increases the electric output from about 85 MW to 130 MW and increases the plant efficiency from 32.7 percent to 50.2 percent.

The HRSG will convert waste heat from the CT exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, two-pressure, nonreheat unit with supplemental duct firing on natural gas only to produce additional power. SCR will be included to control $NO_x$ emissions to 2 ppmvd while burning natural gas and, while no CO catalyst will be included, a spool piece will be provided for future installation.

Table 5-12 presents the operating characteristics of a GE 7EA 1x1 CC repowered unit at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-13 presents estimated emissions for the 1x1 7EA CC unit.

| Table 5-12<br>GE 7EA 1x1 Combined Cycle Characteristics | | |
|---|---|---|
| Ambient Condition | Net Capacity (MW)(1) | Net Plant Heat Rate (Btu/kWh, HHV)(1, 2) |
| Winter (20º F and 100% RH) (Full Load) | 126.6 | 8,095 |
| Summer (102º F and 40% RH) (Full Load) | 106.3 | 8,175 |
| Average (68º F and 77% RH) (Full Load) | 113.6 | 8,060 |
| Average (68º F and 77% RH) (75% Load) | 89.2 | 8,381 |
| Average (68º F and 77% RH) (60% Load) | 76.4 | 8,710 |
| Average (68º F and 77% RH) (Minimum Load – 60%) | 76.4 | 8,710 |

| Table 5-13<br>GE 1x1 7EA Combined Cycle Estimated Emissions(1) | |
|---|---|
| Emission Type | Natural Gas |
| $NO_x$, ppmvd at 15% $O_2$ | 2.0 |
| $NO_x$, lb/MBtu (HHV) | 0.0072 |
| $SO_2$, lb/MBtu (HHV) | 0.0006 |
| Hg, lb/MBtu (HHV) | Not Applicable |
| CO, lb/MBtu (HHV) | 0.0546 |
| $CO_2$, lb/MBtu (HHV) | 114.9 |
| (1)Emissions are at full load at 68º F and include the effects of SCR only (no CO catalyst). | |

***5.2.2.2 7FA Combined Cycle Options.*** Three different options involving the 7FA CT were considered. The 1x1 CC generating unit would include a GE 7FA CTG, HRSG, STG, and cooling tower. The 2x1 CC unit would include a second 7FA CTG and an HRSG. An air-cooled condenser instead of a cooling tower is included for condensing steam from the turbine exhaust for the 2x1 CC at Jack County because of water availability. The greenfield 2x1 CC is similar except that adequate water resources are assumed available, and therefore, cooling towers are assumed for heat rejection. Special consideration will be given to unit design to allow both configurations to cycle. Each CC will be natural gas fired and will include evaporative cooling on each CT.

Each HRSG will convert waste heat from the CT exhaust to steam for use in driving the STG. Each HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing on natural gas only to maintain full STG load at all ambient conditions. SCR will be included to control $NO_x$ to 2 ppmvd while burning natural gas, and while no CO catalyst will be included, a spool piece will be provided for future installation.

The ST is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The ST will have one high-pressure section, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included which will be direct coupled to the ST. The STG will be located outdoors with a building provided for the major auxiliary electrical power equipment. Changing the GE 7FA simple cycle to a 1x1 CC increases the electric output from about 170 MW to 260 MW and increases the plant efficiency from 36 percent to 56 percent.

Table 5-14 presents the operating characteristics of a GE 7FA 1x1 CC at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-15 presents the operating characteristics of a GE 7FA 2x1 CC at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-16 presents estimated emissions for the 1x1 and 2x1 CC units.

### *5.2.3 Solid Fuel Options*

Solid fuels are generally less expensive and have more stable and predictable price patterns than fuels like natural gas and fuel oil. In addition to cost benefits, solid fuels generally have the added advantage of greater long-term availability than natural gas or fuel oil. The disadvantages associated with solid fuel alternatives are greater capital cost and increased emissions, and therefore, increased costs for emissions control technologies to meet emissions regulations. The solid fuel options considered were a CFB boiler and supercritical PC.

Table 5-14
GE 7FA 1x1 Combined Cycle Characteristics

| Ambient Condition | Net Capacity (MW)(1) | Net Plant Heat Rate (Btu/kWh, HHV)(1, 2) |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 257.8 | 7,047 |
| Summer (102º F and 40% RH) (Full Load) | 229.5 | 7,110 |
| Average (68º F and 77% RH) (Full Load) | 240.6 | 6,957 |
| Average (68º F and 77% RH) (75% Load) | 189.6 | 7,211 |
| Average (68º F and 77% RH) (50% Load) | 140.7 | 7,763 |
| Average (68º F and 77% RH) (Minimum Load - Block) | 140.7 | 7,763 |

(1)Net capacity and full load net plant heat rate include degradation factors, cooling towers were used, and performance is preliminary.
(2)Heat rate presented assumes operation on natural gas.
(3)Part load performance percent load is based on gas turbine load point.

Table 5-15
GE 7FA 2x1 Combined Cycle Characteristics

| Ambient Condition | Net Capacity (MW)(1) | | Net Plant Heat Rate (Btu/kWh, HHV)(1, 2) | |
|---|---|---|---|---|
| | Greenfield Site | Jack County Site | Greenfield Site | Jack County Site |
| Winter (20º F and 100% RH) (Full Load) | 514.8 | 506.3 | 7,030 | 7,150 |
| Summer (102º F and 40% RH) (Full Load) | 452.9 | 429.5 | 7,013 | 7,395 |
| Average (68º F and 77% RH) (Full Load) | 481.3 | 471.6 | 6,930 | 7,072 |
| Average (68º F and 77% RH) (75% Load) | 379.5 | 372.4 | 7,183 | 7,320 |
| Average (68º F and 77% RH) (50% Load) | 280.8 | 275.0 | 7,748 | 7,913 |
| Average (68º F and 77% RH) (Minimum Load - 50%) | 280.8 | 275.0 | 7,748 | 7,913 |

(1)Net capacity and full load net plant heat rate include degradation factors; air-cooled condensers were used at Jack County; cooling towers were used at the generic site; and performance is preliminary.
(2)Heat rate presented assumes operation on natural gas.
(3)Part-load performance percent load is based on gas turbine load point.

Table 5-16
GE 7FA Combined Cycle Estimated Emissions(1)

| Emission Type | 1x1 Natural Gas | 2x1 Natural Gas |
|---|---|---|
| $NO_x$, ppmvd at 15% $O_2$ | 2 | 2 |
| $NO_x$, lb/MBtu (HHV) | 0.0073 | 0.0073 |
| $SO_2$, lb/MBtu (HHV) | 0.0006 | 0.0006 |
| Hg, lb/MBtu (HHV) | NA | NA |
| CO, lb/MBtu (HHV) | 0.0165 | 0.0166 |
| $CO_2$, lb/MBtu (HHV) | 114.8 | 114.8 |
| PM10 (Front half catch), lb/MBtu (HHV) | 0.0056 | 0.0056 |
| PM10 (Front and back half catch), lb/MBtu (HHV) | 0.0109 | 0.0109 |

(1)Emissions are at full load at 68º F and include the effects of SCR only (no CO catalyst).

Coal is the most widely used fuel for the production of power, and most coal burning power plants use PC boilers. PC units have the advantage of utilizing a proven technology with a very high reliability level. They can be sized very large, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain, and respond to load changes better than CFB boilers. However, CFB boilers are well suited for burning low quality coals like lignite.

Supercritical PC units were the only PC units evaluated. While supercritical units are generally more efficient than subcritical units, supercritical units have a disadvantage of requiring larger capacity generating units. The efficiency comes at the cost of considerations of economies of scale.

***5.2.3.1 Supercritical Pulverized Coal.*** The supercritical PC unit being considered has a nominal generating capacity of 500 MW. A supercritical unit is the only PC generating unit being considered.

The PC unit will include a wet flue gas desulfurization (FGD) scrubber process to remove $SO_2$ emissions. The scrubber would be designed to meet Best Available Control Technology (BACT) requirements. The $SO_2$ scrubber would produce calcium sulfate (gypsum) as a byproduct, which is acceptable for producing wallboard. The production of gypsum would help reduce the solid waste stream from a supercritical PC generating facility.

The unit will employ SCR to reduce $NO_x$ emissions. The SCR uses ammonia or urea in the presence of a catalyst to remove $NO_x$ gas from the flue gas. The SCR would be designed to meet BACT requirements.

Aside from the mercury control that is obtained as a cobenefit of the $NO_x$ and $SO_2$ emission controls, there will be no added mercury control. The EPA estimates that all CAMR Phase I mercury emissions will be achieved through the previously described co-benefit process. Long-term mercury control options are still in the design phase as of the time of this report.

The supercritical PC unit will also include fabric filter to reduce emissions of particulate matter (PM). Ash collected by the fabric filter would be managed in an onsite landfill or sold to the cement industry.

Table 5-17 presents the operating characteristics of the supercritical PC alternative at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-18 presents estimated emissions.

Table 5-17
500 MW Subcritical Pulverized Coal Plant Characteristics[1]

| Ambient Condition | Net Capacity (MW) | Full Load Net Plant Heat Rate (Btu/kWh, HHV) |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 502.9 | 8,928 |
| Summer (102º F and 40% RH) (Full Load) | 491.8 | 9,158 |
| Average (68º F and 77% RH) (Full Load) | 500.0 | 8,996 |
| Average (68º F and 77% RH) (75% Load) | 369.5 | 9,241 |
| Average (68º F and 77% RH) (50% Load) | 239.0 | 9,768 |
| Average (68º F and 77% RH) (Minimum Load – 40%) | 186.8 | 10,194 |

(1)Data based on burning 100 percent PRB subbituminous coal.

Table 5-18
Supercritical Pulverized Coal Unit Estimated Emissions[1]

| Emission Type | 500 MW |
|---|---|
| $NO_x$, lb/MBtu | 0.07 |
| $SO_2$, lb/MBtu | 0.10 |
| CO, lb/MBtu | 0.10 |
| $CO_2$, lb/MBtu | 205 |
| Hg, lb/TBtu | 1.30 |

(1)Emissions at full load at 68º F.

***5.2.3.2 Circulating Fluidized Bed.*** In a CFB boiler, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water cooled membrane walls with specially designed air nozzles, which distribute the air uniformly. The fuel and limestone are fed into the lower bed where, in the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air, and the balance of the combustion air is introduced at the top of the lower, dense bed. Such staged combustion limits the formation of $NO_x$.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed, and therefore, fluidizing air elutriates the particles through the combustion chamber to the cyclone separators at the furnace exit. The captured solids, including any unburned carbon and unutilized calcium oxide (CaO), are reinjected directly back into the combustion chamber without passing through an external recirculation. The internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

One of the key and most recognized advantages of CFB technology is its ability to burn a wide variety of low grade fuels such as peat, coal wastes, sludges, municipal wastes, biomass, and petroleum coke, in addition to most grades of coal. CFBs can be designed to burn a range of fuels individually or in combination, providing the end-user with some flexibility in choosing the best economical mix to minimize generation costs. For evaluation purposes, Texas lignite coal was considered for the CFB.

CFBs are also widely recognized as being inherently low in emissions, due in large part to low combustion temperatures which reduce thermal $NO_x$ formation, and the ability to introduce limestone directly into the furnace to control $SO_2$ emissions. CFB technology has matured to the point that operating plants have demonstrated availability comparable to the most modern solid fuel-fired plants.

The CFB unit will include two steam generators and one condensing STG. The STG will include a standard sound enclosure and will be housed in an engineered generation building that includes a control room, electrical equipment room, battery room, motor control center, switchgear room, and various offices. Selective noncatalytic reduction (SNCR) will be used to control $NO_x$ emissions, and a fabric filter will be used to control particulate emissions. In addition to limestone injection into the boiler, a polishing circulating dry scrubber will also be used for further $SO_2$ control. The cooling system will consist of circulating water pumps and a wet mechanical draft cooling tower.

Table 5-19 present the operating characteristics of the CFB alternatives at a winter temperature of 20º F, a summer temperature of 102º F, and an annual average temperature of 68º F. Table 5-20 presents the estimated emissions from the CFB units.

## 5.3 Emerging Generation Technologies

### *5.3.1 Integrated Gasification Combined Cycle*

In the IGCC power generation process, fuel (petroleum coke, coal, or other fuel) is converted to syngas, which is treated and then combusted in gas turbines in a CC power generation unit. IGCC advantages include low water usage and high efficiency relative to CFB and PC technologies. The cost and availability are currently significant disadvantages for IGCC, but the technology is expected to become more competitive as additional IGCC plants are built and the technology matures. IGCC has the potential for significant efficiency improvements resulting from improvements in F-Class CTs, which are currently used in IGCC applications, and the future use of G- and H-Class CTs. The cost associated with reducing mercury and possible future $CO_2$ emissions is lower for IGCC than for CFB and PC technologies.

There have been approximately 20 IGCC power plants operated throughout the world. Only four coal fueled IGCC plants are currently operating. These plants have capacities ranging from 250 MW to 300 MW. Each of these plants has operated for more than 7 years, and as an aggregate they have modestly demonstrated the IGCC technology on a commercial scale.

The Shell Quench gasifiers assumed in this analysis are entrained flow gasifiers, which are typical of the gasification technologies that have been previously demonstrated in the United States. Two IGCC plants have been demonstrated in the US, both were government subsidized. Both demonstrated plants experienced numerous problems during their initial years of operation, which have resulted in poor availability and either a net plant heat rate or a net output worse than design. Plant modifications and O&M procedure improvements have improved performance.

The complexity and relative immaturity in technology of the IGCC allows opportunities for deficiencies in design, vendor supplied equipment, construction, operation, and maintenance. However, the experience gained from operating IGCC units will improve the initial availability of new IGCC units. Significant downtime should still be expected during the first several years of plant operation. This makes IGCC a more risky technology than PC or CFB options for meeting future capacity requirements with good reliability. However, long-term availabilities for a single train IGCC unit are expected to range from 80 to 85 percent. Long-term IGCC forced outage rates are expected to range from 7 to 10 percent. If the gas turbine(s) can operate on backup fuel when syngas is not available, the CC availability is expected to exceed 90 percent.

Table 5-19
500 MW Circulating Fluidized Bed Characteristics

| Ambient Condition | Net Capacity (MW)(1) | Full Load Net Plant Heat Rate (Btu/kWh, HHV)(1) |
|---|---|---|
| Winter (20º F and 100% RH) (Full Load) | 502.8 | 10,383 |
| Summer (102º F and 40% RH) (Full Load) | 493.2 | 10,590 |
| Average (68º F and 77% RH) (Full Load) | 500.0 | 10,445 |
| Average (68º F and 77% RH) (75% Load) | 369.0 | 10,792 |
| Average (68º F and 77% RH) (50% Load) | 237.5 | 11,491 |
| Average (68º F and 77% RH) (Minimum Load – 40%) | 185.0 | 12,012 |

(1)Performance includes degradation and cooling towers for heat rejection, and is preliminary.

Table 5-20
CFB Unit Estimated Emissions(1)

| Emission Type | 500 MW |
|---|---|
| $NO_x$ lb/MBtu | 0.09 |
| $SO_2$ lb/MBtu | 0.10 |
| Hg lb/TBtu | 1.55 |
| CO lb/MBtu | 0.12 |
| $CO_2$ lb/MBtu | 208 |

(1)Emissions at full load at 68º F.

Emissions will be controlled before the syngas reaches the CT. Sulfur will be treated with a sulfur recovery unit (SRU) which burns approximately one third of the sulfur in hydrogen sulfide ($H_2S$) form, and uses the heat to further separate the sulfur. The separated sulfur can then be captured in solid or liquid form.

There are a few primary gasification technology providers in the market including GE, ConocoPhillips, and Shell. One IGCC alternative was considered for evaluation. The IGCC alternative considered for Brazos Electric would consist of a single 2x1 GE 7FB CC and two 100 percent Shell Quench entrained flow gasifiers. The advantage of having two gasifiers is an increased reliability. This advantage comes with the cost of having a higher net plant heat rate and a lower net capacity. The Shell Quench entrained flow gasifiers assumed are similar to the gasification technologies that have been previously demonstrated in the US. It is assumed that the IGCC plant would operate on PRB coal. The PRB coal is assumed to have a heat content of 8,800 Btu/lb HHV, 0.4 percent sulfur, and 6.6 percent ash. The IGCC alternative is assumed to be located at a greenfield site.

Due to the relative immaturity of the technology and the significant downtime expected in the first few years, IGCC may not be the ideal technology for near-term capacity additions. However, IGCC cost and performance characteristics have been evaluated for a 2x1 GE 7 FB CC unit with two gasifiers to give an indication of the cost and operating characteristics associated with this technology.

Table 5-21 presents the anticipated output and performance of the IGCC alternative at a winter temperature of 20º F, a summer temperature of 102º F, and annual average temperature conditions of 68º F. Estimated emissions for the IGCC alternative are presented in Table 5-22.

### *5.3.2 Nuclear Fission*

The use of a uranium fueled nuclear fission process to create energy has been utilized in the United States for several decades. Once inside a nuclear reactor, uranium atoms are bombarded by neutrons. Each time a neutron is absorbed by a uranium atom, the atom becomes unstable and splits, a process known as fission. During this process, the atom produces additional neutrons, usually two and a half for every fission, which go on to split more uranium atoms, creating more neutrons. This scenario perpetuates, resulting in a chain reaction. The fission process generates heat and occurs in the reactor core, where the fuel transfers its heat to water that is then circulated to the steam generator.

| Table 5-21<br>Shell 2x1 GE 7 FB IGCC Characteristics | | |
|---|---|---|
| Ambient Condition | Net Capacity (MW)[1] | Net Plant Heat Rate (Btu/kWh, HHV)[1,2] |
| Winter (20º F and 100% RH) (Full Load) | 564 | 8,780 |
| Summer (102º F and 40% RH) (Full Load) | 525 | 9,340 |
| Average (68º F and 77% RH) (Full Load) | 545 | 9,085 |
| Average (68º F and 77% RH) (75% Load)[3] | 428 | 9,590 |
| Average (68º F and 77% RH) (50% Load)[3] | 292 | 10,550 |

(1)Performance assumes operation on PRB coal at 950 foot elevation and two 100 capacity gasifiers.
(2)Net capacity and net plant heat rate include degradation.
(3)Part-load performance percent is based on CT load point.

| Table 5-22<br>Shell 2x1 GE 7 FB IGCC Unit Estimated Emissions[1] | |
|---|---|
| Emission Type | PRB Subbituminous Coal |
| $NO_x$, lb/MBtu | 0.06 |
| $SO_2$, lb/MBtu[2] | 0.015 |
| Hg, lb/MWh | 0.000078 |
| $CO_2$, lb/MBtu | 215 |
| CO, lb/MBtu | 0.05 |

(1)Emissions are at full load at 68º F and do not include the effects of SCR or CO catalyst. There is concern with HRSG fouling when operating the current design of IGCC plants with these systems.
(2)$SO_2$ emissions include $SO_3$.

Currently, nuclear power in the United States faces obstacles related to public perception, capital costs, and environmental issues concerning disposal of spent fuel. Combined, these factors explain why nuclear plants have fallen out of favor as a generating resource. However, rising fuel prices, greenhouse gas emission concerns, and increasing energy demand may make nuclear fission a viable option for producing power in the future.

Westinghouse and GE are currently developing and licensing nuclear units with the Nuclear Regulatory Commission (NRC). The two units are the Westinghouse AP-1000 and the GE ESBWR. The AP-1000 was approved by the NRC in 2004, and the NRC is expected to approve the ESBWR in 2007.

The units consist of a nuclear island (NI), turbine island (TI), radwaste building, cooling tower, and additional yard facilities. The units described in this subsection are assumed to be located at a greenfield site in Texas.

The TI consists of the ST and the switchgear building. The switchgear building includes standard electrical equipment and switchgear for a large nuclear unit.

The radwaste building has both liquid and solid radwaste treatment systems. In addition to the treatment systems, costs for the radwaste building include communications, lighting, and security systems.

The cooling tower is one of the major yard facilities and is assumed to be a mechanical draft cooling tower with a pump house and retention pond. Other yard facilities include transformers, fuel and chemical storage systems, a makeup water treatment building, grounding system, radwaste tunnel, and a service building.

Nuclear units have virtually no emissions, and there will be no emissions control equipment included with the plant. Currently there is no way to dispose of spent fuel rods after the fission process, but the operating costs of the nuclear unit include such expenses in the future. The estimated operating characteristics of the AP-1000 and ESBWR nuclear units are presented in Table 5-23.

## 5.4 Cost Estimation and Construction Schedule

### *5.4.1 Capital Costs, O&M Costs, and Schedule Summary*

The capital costs, O&M costs, and schedules for the generating alternatives are summarized in Table 5-24. All costs are provided in 2006 dollars. The EPC cost is inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. An allowance for owner’s costs is also included to cover costs outside of the EPC contract scope based on Black & Veatch’s experience. Actual owner’s costs can vary significantly; however, the assumed allowance is representative of typical owner’s costs exclusive of escalation, financing fees, and interest during construction. These excluded costs would be estimated and included during the evaluation process. Escalation should be included to the midpoint of construction.

Table 5-23
Nuclear Unit – Performance and Costs

| | Westinghouse AP-1000 | GE ESBWR |
|---|---|---|
| Commercial Status | Development | Development |
| Construction Period (months) | 72 | 72 |
| **Performance** | | |
| Net Capacity (MW) | 1,200 | 1,578 |
| Net Plant Heat Rate (Btu/kWh) | 9,715 | 9,715 |
| Capacity Factor (percent) | 80 to 90 | 80 to 90 |
| **Economics, $2006** | | |
| Total Project Cost ($/kW) | 2,191 | 1,849 |
| Fixed O&M ($/kW-yr) | 64 | 64 |
| Levelized Cost(1) ($/MWh) | 54 to 61 | 50 to 55 |

(1)The low end of the levelized cost is based on a 90 percent capacity factor, and the high end is based on an 80 percent capacity factor.

Fixed and variable O&M costs are also provided in 2006 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Variable costs include outage maintenance, consumables, and replacements dependent upon operation.

Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided below.

### *5.4.2 Startup and Forced Outage Assumptions*

The startup and forced outage assumptions for the generating alternatives are presented in Table 5-25. Startup times in minutes are from initial turbine roll or boiler ignition to 100 percent load.

Table 5-24
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives

| ID No. | Supply Alternative | EPC Cost ($Millions) | Owner's Cost ($Millions) | IDC and Escalation ($Millions) | Total Cost ($Millions) | MW at 68° F | Total Cost ($/kW) at 68° F | Fixed O&M ($/kW-yr) | Variable O&M ($/MWh) | Construction Schedule (Months) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Simple Cycle GE LM6000 (Two-unit Block) | 54.90 | 13.70 | 0.00 | 68.60 | 87.4 | 785.00 | 16.90 | 3.10 | 10 |
| 2 | Simple Cycle GE LMS100 | 55.67 | 11.32 | 0.00 | 66.99 | 95.6 | 701.00 | 11.40 | 3.90 | 14 |
| 3 | Simple Cycle GE 7FA with SCR | 60.42 | 12.29 | 0.00 | 72.71 | 154.8 | 470.00 | 6.20 | 16.20(1) | 12 |
| 4 | Simple Cycle GE 7FA without SCR | 54.62 | 11.11 | 0.00 | 65.73 | 155.9 | 422.00 | 6.20 | 15.80(1) | 11 |
| 5 | 1x1 GE 7FA CC | 131.90 | 27.30 | 0.00 | 159.2 | 240.6 | 662.00 | 7.40 | 4.40 | 27 |
| 6 | 2x1 GE 7FA CC (Jack County) | 246.67 | 51.06 | 0.00 | 297.73 | 471.6 | 631.00 | 5.30 | 3.30 | 28 |
| 7 | 2x1 GE 7FA CC (Greenfield) | 240.96 | 49.88 | 0.00 | 290.84 | 481.3 | 604.00 | 6.30 | 4.40 | 28 |
| 8 | 500 MW Supercritical PC | 747.40 | 160.13 | 0.00 | 907.53 | 500 | 1815.00 | 24.20 | 1.90 | 42 |
| 9 | 500 MW CFB | 667.30 | 142.97 | 0.00 | 810.27 | 500 | 1621.00 | 21.80 | 4.40 | 32 |
| 10 | 1x1 GE 7EA CC Repowering | 74.27 | 15.38 | 0.00 | 89.65 | 113.6 | 793.00 | (2) | 4.10 | 26 |
| 11 | 2x1 GE 7FB IGCC – Two-100% Shell Quench Gasifiers | 1,020 | 204 | 0.00 | 1,224 | 545 | 2,246 | 27.00 | 6.20 | 38 |

(1)The variable O&M cost includes cost of maintenance inspection and one major overhaul. The major overhaul is expected to occur anytime between year 15 and year 20 of operation depending on the actual number of starts and the plant capacity factor.
(2)Costs to be estimated by Brazos Electric based on existing staff and other fixed O&M expenses.

Table 5-25
Startup and Forced Outage Assumptions

| ID No. | Supply Alternative | Cold Start (Minutes) | Hot Start (Minutes) | Warm Start (Minutes) | Ramp Rates (%/minute) | Forced Outage Rate (%) |
|---|---|---|---|---|---|---|
| 1 | Simple Cycle GE LM6000 (Two-Unit Block) | 10 - 15 | 10 - 15 | 10 - 15 | 18 | 1 - 5 |
| 2 | Simple Cycle GE LMS100 | 10 - 15 | 10 - 15 | 10 - 15 | 18 | 1 - 5 |
| 3 | Simple Cycle GE 7FA | 26 | 26 | 26 | 8 | 1 - 5 |
| 4 | 1x1 GE 7EA CC | 230 | 70 | 140 | 5 | 1 - 5 |
| 5 | 1x1 GE 7FA CC | 240 | 80 | 150 | 5 | 1 - 5 |
| 6 | 2x1 GE 7FA CC | 240 | 80 | 150 | 5 | 1 - 5 |
| 7 | Supercritical PC (500 MW) | 480 | 120 | 300 | 6 | 5 - 8 |
| 8 | CFB (500 MW) | 600 | 120 | 360 | 5 | 5 - 8 |
| 9 | 250 MW IGCC – Two-100% Shell Quench Gasifiers | 1,200 | 240 | 720 | 2 - 3 | 7 - 10 |

# 6.0 Renewable Technologies Evaluation

Renewable energy technologies are diverse; they include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. The technical feasibility and cost of energy from nearly every form of renewable energy has improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies and, in most countries, the renewable fraction of total electricity generation remains small. Nevertheless, the field is rapidly expanding from occupying niche markets to making meaningful contributions to the world's electricity supply.

This section provides an overview and analysis of various renewable energy technologies, including the following:

- Solid biomass (direct-fired and co-firing).
- Biogas (anaerobic digestion and landfill gas).
- Wind (onshore).
- Solar (solar thermal and solar photovoltaic).
- Hydroelectric.

Generally, each technology is described with respect to its operating principles, applications, resource availability in Texas, cost and performance characteristics, and environmental impacts. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and a literature review. Capital costs are in 2006 dollars and reflect the total project cost, including direct and indirect costs. The estimated levelized cost ranges of these renewable energy resources are represented graphically in Figures 6-1 and 6-2.

## 6.1 Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, co-fired biomass and biomass gasification as described in the following subsections.

### *6.1.1 Direct-Fired Biomass*

According to the US Department of Energy (DOE), there is about 35,000 MW of installed biomass combustion capacity worldwide.[1] Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

[1] US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at: http://bioenergy.ornl.gov/faqs

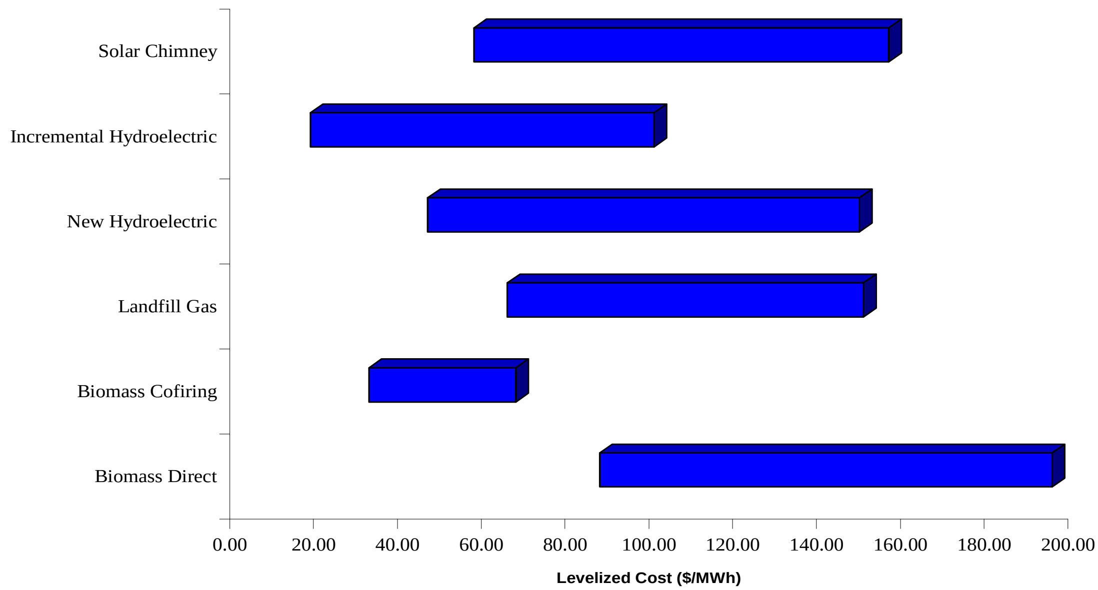


Figure 6-1
Levelized Cost Ranges of Baseload Renewable Energy Resources

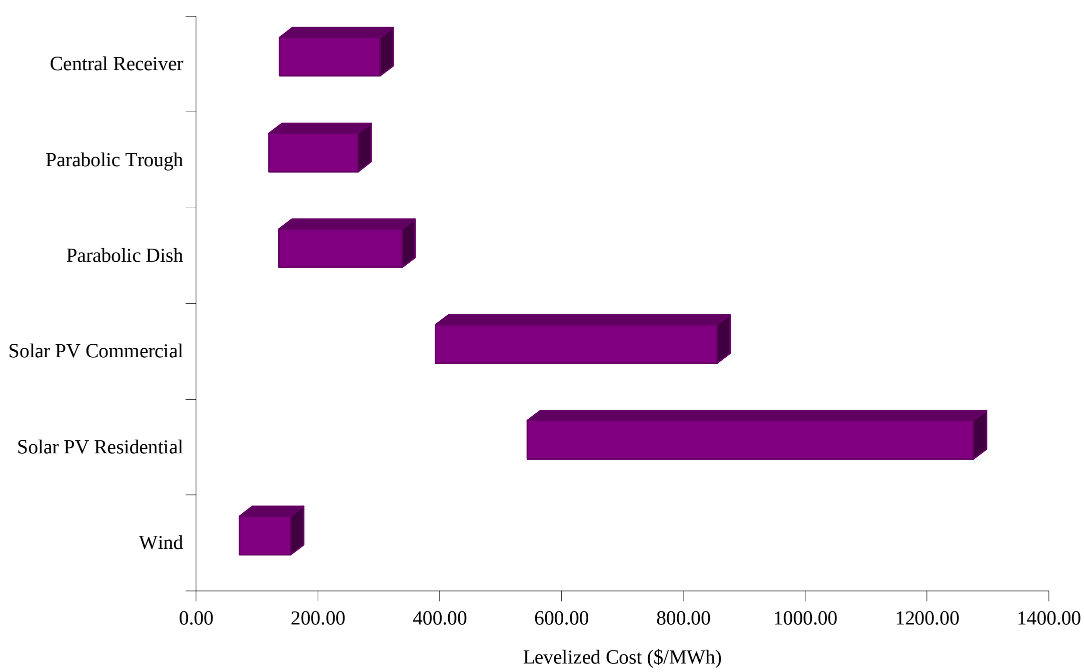


Figure 6-2
Levelized Cost Ranges of Peak Load Renewable Energy Resources

### *Operating Principles*

Direct biomass combustion power plants in operation today use the same steam Rankine cycle introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification CC and biomass pyrolysis, are currently under development; however, there are no IGCC plants currently operating with biomass as a primary fuel.

### *Applications*

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating value of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

### *Resource Availability*

To be economically feasible, dedicated biomass plants are generally located either at the source of a fuel supply (such as at a sawmill) or within 100 miles of numerous suppliers. Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically comprised of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

While Texas has fewer biomass resources than the Midwestern states to the north, significant biomass resources exist in the panhandle and the eastern part of the state, including large amounts of urban wood waste in more heavily populated areas. The expected cost of clean wood residues can vary by up to 50 percent, depending on the type of residue, quantity, and hauling distance. A base delivered value of $2.00/MBtu was assumed in this analysis.

### *Cost and Performance Characteristics*

Table 6-1 presents typical characteristics of a 30 MW stoker boiler biomass plant with Rankine cycle using wood waste as fuel.

Table 6-1
Direct Biomass Combustion Technology Characteristics

| | |
|---|---|
| **Performance** | |
| Typical Duty Cycle | Baseload |
| Net Plant Capacity (MW) | 30 |
| Net Plant Heat Rate (HHV, Btu/kWh) | 14,500 |
| Capacity Factor (percent) | 70 to 90 |
| **Economics ($2006)** | |
| Total Project Cost ($/kW) | 2,300 to 3,350 |
| Fixed O&M ($/kW-yr) | 70 |
| Variable O&M ($/MWh) | 10 |
| Levelized Cost(1) ($/MWh) | 86 to 108 |
| **Technology Status** | |
| Commercial Status | Commercial |
| Installed US Capacity (MW) | 7,000 |

(1)The low ends of the levelized costs are based on a 90 percent capacity factor and a capital cost of $2,300/kW. The high ends of the levelized costs are based on a 70 percent capacity factor and a capital cost of $3,350/kW. Fuel cost is assumed to be $2.00/MBtu.

### Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While $CO_2$ is emitted during biomass combustion, a nearly equal amount of $CO_2$ is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and, therefore, produce less $SO_2$. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. However, biomass combustion still must include technologies to control emissions of $NO_x$, particulate matter (PM), and CO to maintain BACT standards.

## 6.1.2 Biomass Co-Firing

### Operating Principles

One of the most economical methods to burn biomass is to co-fire it with coal. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same basic power conversion technology but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiency at a lower cost. Through co-firing, biomass benefits from this higher efficiency at a more competitive cost than a stand-alone, direct-fired biomass plant.

### Applications

There are several methods of biomass co-firing that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient enough to co-fire biomass.

Cyclone boilers and PC boilers (the most common in the utility industry) require a smaller fuel size than stokers and fluidized beds and may necessitate processing of the biomass prior to combustion. There are two basic approaches to co-firing in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass. The first approach blends the fuels and feeds the mixture to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to approximately 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher co-firing percentages (10 to 15 percent) in a PC unit, but costs more than processing a fuel blend.

Even at these limited co-firing rates, plant owners and operators have raised numerous concerns about the negative effects of co-firing on plant operations. These include the following:

- Negative impact on plant capacity.
- Negative impact on boiler performance.
- Ash contamination decreasing the quality of combustion ash.
- Increased O&M costs.
- Minimal $NO_x$ reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative impacts on SCR air pollution control equipment (catalyst poisoning).

These concerns have hampered the adoption of widespread biomass co-firing by electric utilities in the United States. However, most of these concerns can be addressed through proper system design, fuel selection, and limits on the amount of co-firing.

Coal and biomass co-firing can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW CFB in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning anywhere from 100 percent biomass to 100 percent coal.

### *Resource Availability*

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other country in the world. The United States-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2.02 trillion kWh in 2005, which comprised 52.2 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass co-firing would increase electricity production from biomass by nearly 400 percent. The local resources available for biomass co-firing are the same as those for dedicated biomass plants. Biomass is assumed to be available for $2.00/MBtu.

### *Cost and Performance Characteristics*

Table 6-2 presents typical characteristics for a biomass and coal co-fired plant. The characteristics are based on co-firing 20 MW of biomass (separate injection) in a new 750 MW PC power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system.

### *Environmental Impacts*

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, co-firing biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of $SO_2$, CO, $NO_x$, and heavy metals, such as mercury.

## 6.2 Landfill Gas

### *Operating Principles*

Landfill gas (LFG) is produced by the decomposition of the organic portion of landfill waste. LFG typically has a methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to hedge the risk of explosion associated with LFG. From a generating perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy (WTE) technologies. Currently, there are more than 600 LFG energy recovery systems installed in 20 countries.

Table 6-2
Co-Fired Biomass Technology Characteristics

| | |
|---|---|
| **Performance** | |
| Typical Duty Cycle | Typically baseload, depends on host |
| Net Plant Capacity (MW) | 20 |
| Net Plant Heat Rate (Btu/kWh) | Increase 0.2 to 0.5 percent |
| Capacity Factor (percent) | Unchanged |
| **Economics (Incremental Costs in $2006)** | |
| Total Project Cost(1) ($/kW) | 200 to 400 |
| Total Project Cost(2) ($/kW) | 8 to 16 |
| Fixed O&M(1) ($/kW-yr) | 5 to 10 |
| Fixed O&M(2) ($/kW-yr) | 0.2 to 0.4 |
| Variable O&M ($/MWh) | Unchanged |
| Levelized Cost(3) ($/MWh) | 31 to 35 (incremental cost) |
| **Technology Status** | |
| Commercial Status | Commercial |
| Installed US Capacity (MW)(4) | >2,000 MW |

(1)Based on biomass capacity.

(2)Based on total plant capacity (750 MW).

(3)The low end of the levelized cost is based on a net biomass capacity of 20 MW, heat rate increase of 0.2 percent, capital cost of $200/kW, and fixed O&M of $5/kW-yr. The high end of the levelized cost is based on a net plant capacity of 20 MW, heat rate increase of 0.5 percent, capital cost of $400/kW, and fixed O&M cost of $10/kW-year.

(4)Estimate for the biomass portion of plants that co-fire coal and biomass. Actual capacity is unknown.

### *Applications*

LFG can be used to generate electricity and process heat or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. Approximately 75 percent of the landfills that generate electricity use internal combustion engines.[2] Depending on the scale of the gas collection facility, it may be feasible to generate power via a CT or a boiler and ST. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

### *Resource Availability*

Gas production at a landfill is dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

### *Cost and Performance Characteristics*

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill which has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 6-3 presents cost and performance estimates for typical LFG projects using reciprocating engines. Fuel costs are assumed to be $2/MMBtu.

### *Environmental Impacts*

LFG combustion releases pollutants similar to many other fuels but is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than $CO_2$. Collecting the gas and converting the methane to $CO_2$ through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

[2] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

Table 6-3
Landfill Gas Technology Characteristics

| | |
|---|---|
| **Performance** | |
| Typical Duty Cycle | Baseload |
| Net Plant Capacity (MW) | 0.2 to 15 |
| Net Plant Heat Rate (HHV, Btu/kWh) | 11,500 |
| Capacity Factor (percent) | 70 to 90 |
| **Economics ($2006)** | |
| Total Project Cost ($/kW) | 1,350 to 2,800 |
| Variable O&M ($/MWh) | 15 |
| Levelized Cost(1) ($/MWh) | 64 to 85 |
| **Technology Status** | |
| Commercial Status | Commercial |
| Installed US Capacity (MW) | 1,100 |

(1)The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90 percent capacity factor, and a capital cost of $1,350/kW. The high end is based on a net plant capacity of 0.2 MW, a 70 percent capacity factor, and a $2,800/kW capital cost.

## 6.3 Wind

### *Operating Principles*

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade, in percentage terms, with around 30 percent annual growth in worldwide capacity over the last 5 years. Cumulative worldwide wind capacity is now estimated to be more than 50,000 MW. Total installed wind capacity in the United States was 9,149 MW at the beginning of 2006. The US wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has been renewed several times and is currently set to expire on December 31, 2007.

### *Applications*

Typical utility scale wind energy systems consist of multiple wind turbines that range in size from 1 to 2 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors generally ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system.

### *Resource Availability*

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 6-4. Texas is a national leader in wind energy installations, with 2,400 MW of currently installed capacity and nearly 600 MW under construction. Wind resources are best in and just to the south of the panhandle of Texas, as well as a small region of high wind in the western part of the state. There are also significant resources in the coastal regions in the southeast part of the state. The majority of current installations are concentrated near Abiline in Taylor County and in Upton and Pecos counties. Winds in these areas are generally Class 3 and 4, with smaller areas of higher class winds.

### *Cost and Performance Characteristics*

Table 6-5 provides typical characteristics for a 50 to 100 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand has driven up the cost by as much as 40 percent. Additionally, due to the increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2008. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for newly installed wind projects in the United States has increased from about 24 percent before 1999 to over 32 percent in 2005.

Table 6-4
US DOE Classes of Wind Power

| Wind Power Class | Height Above Ground: 50 m (164 ft)[1] | |
|---|---|---|
| | Wind Power Density ($W/m^2$) | Speed[2] (m/s) |
| 1 | 0 to 200 | 0 to 5.60 |
| 2 | 200 to 300 | 5.60 to 6.40 |
| 3 | 300 to 400 | 6.40 to 7.00 |
| 4 | 400 to 500 | 7.00 to 7.50 |
| 5 | 500 to 600 | 7.50 to 8.00 |
| 6 | 600 to 800 | 8.00 to 8.80 |
| 7 | 800 to 2000 | ≥ 8.80 |

(1)Vertical extrapolation of wind speed based on the 1/7 power law, as defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991*.

(2)Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 meters (5 percent per 5,000 ft) elevation.

Table 6-5
Wind Technology Characteristics

| | |
|---|---|
| **Performance** | |
| Typical Duty Cycle | As Available |
| Net Plant Capacity, MW | 50-150 |
| Capacity Factor, percent | 28-40* |
| **Economics ($2004)** | |
| Total Project Cost, $/kW | 1,600 to 1,900 |
| Fixed O&M, $/kW-yr | 28 |
| Variable O&M, $/MWh | 8 |
| Levelized Cost, $/MWh | 55 to 84** |
| **Technology Status** | |
| Commercial Status | Commercial |
| Installed US Capacity, MW | 10,039 |

*Representative of existing projects in Texas.

**The low end of the levelized cost is based on net plant capacity of 150 MW, capacity factor of 40 percent, and capital cost of $1,600/kW. The high end of the levelized cost is based on net plant capacity of 50 MW, capacity factor of 28 percent, and capital cost of $1,900/kW.

### *Environmental Impacts*

Wind is a clean generation technology from the emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and public involvement during the planning process.

## 6.4 Solar

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar photovoltaics (PVs).

### *6.4.1 Solar Thermal*

### *Operating Principles*

Solar thermal technologies convert the sun’s energy to electricity by capturing heat. Technological advances have expanded solar thermal applications to high magnitude energy collection and power conversion on a utility scale. The leading solar thermal technologies include parabolic trough, parabolic dish, power tower (central receiver), and solar chimney.

With adequate resources, solar thermal technologies are appropriate for a wide range of intermediate and peak load applications, including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in California currently generate more than 350 MW.

Most solar thermal systems (parabolic trough, parabolic dish, and central receiver) transfer the heat in solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. By using thermal storage or by combining the solar generation system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

Unlike the three other solar thermal technologies, solar chimneys do not generate power using a thermal heat cycle. Instead, they generate and collect hot air in a large (several square miles) greenhouse. A tall chimney is located in the center of the greenhouse. As the air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current that rotates a collection of air turbines.

### *Applications*

The larger solar thermal technologies (parabolic trough, central receiver, and solar chimney) are currently not economically competitive with other central station generation options (such as a natural gas fired CC units). Parabolic dish engine systems are small and modular and can be placed at load sites, directly offsetting retail electricity purchases. However, these systems have not been used in commercial applications.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the southwest US desert. There are nine Solar Electric Generating Station (SEGS) parabolic trough plants in the Mojave Desert that have a combined capacity of 354 MW. Other parabolic trough plants are being developed, including a 64 MW plant in Nevada and several 50 MW plants in Spain.

Parabolic dish engine systems of approximately 25 kW have been developed and are now being actively marketed. Recently, installation was completed on a six-dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement (PPA) with Stirling Energy Systems (SES) for between 500 to 850 MW of capacity of dish/Stirling units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these PPAs remains confidential. If large deployments of dish/Stirling systems materialize, they are expected to drastically reduce capital and O&M costs and increase system reliability.

The US government has funded two utility-scale central receiver power plants: Solar One and its retrofit, Solar Two. Solar Two was a 10 MW installation near Barstow, California, but it is no longer operating because of reduced federal support and high operating costs.

The first commercial chimney project has been proposed in Australia. Originally, this project was planned to be 200 MW with a chimney 1 kilometer (0.62 mile) tall and a greenhouse 5 kilometers (3.1 miles) in diameter. The estimated cost of that system was $700 million. More recently, the project has been scaled down to 50 MW. Cost and dimension data for the scaled down system are not available.

### *Resource Availability*

Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation (DI). DNI, which typically comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. DI is the part that has been scattered by the atmosphere or is reflected off the ground or other surfaces. On a cloudy day, all of the radiation is diffuse. The vector sum of DNI and DI is termed global insolation. Systems that concentrate solar energy use only DNI, while nonconcentrating systems use global insolation. Concentrating solar thermal systems (troughs, dishes, and central receivers) use DNI. Lower latitudes with minimum cloud coverage offer the greatest solar concentrator potential. In Texas, DNI ranges from about 4.5 $kW/m^2$/day in the eastern part of the state to about 7.5 $kW/m^2$/day on the western edge of the state. Some locations in the southwestern United States can have DNI as high as 8.5 $kW/m^2$/day.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems that include storage allow dispatch that can improve the ability to meet peaking requirements. Land requirements for solar thermal systems are about 5 to 8 acres/MW.

### *Cost and Performance Characteristics*

Representative characteristics for the four solar thermal power plant technologies previously described are presented in Table 6-6.

## *6.4.2 Solar Photovoltaic*

PVs have achieved considerable consumer acceptance over the last few years. PV module production tripled between 1999 and 2002. PV installations reached a worldwide output of over 927 MW in 2004. Worldwide grid-connected residential and commercial installations grew from 120 MW per year in 2000 to 770 MW per year in 2004.[3] The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV attractive. Large-scale (>100 kW) PV installations have been added at a rate of about 5 MW per year in recent years.[4]

### *Operating Principles*

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystal silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, with some reduction in cell efficiency. Thin film cells significantly reduce cost per unit area, but result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications.

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[3] Installed PV Power as of the end of 2004, http://www.oja-services.nl/iea-pvps/isr/01.htm.
[4] Paul Maycock, "PV Market Update," *Renewable Energy World*, July-August 2003.

Table 6-6
Solar Thermal Technology Characteristics[(1)]

| | Parabolic Trough | Parabolic Dish | Central Receiver | Solar Chimney |
|---|---|---|---|---|
| **Performance** | | | | |
| Typical Duty Cycle | Peaking - Intermediate | As Available - Peaking | Peaking - Intermediate | Intermediate - Baseload |
| Net Plant Capacity (MW) | 100 | 1.2 | 50 | 200 |
| Integrated Storage | 6 hours | None | 6 hours | Yes |
| Capacity Factor (percent) | 35 to 40 | 20 to 25 | 35 to 40 | 60 to 80 |
| **Economics ($2006)** | | | | |
| Total Project Cost ($/kW) | 3,600 to 4,600 | 3,100 to 4,100 | 4,100 to 5,100 | 4,000 to 5,000 |
| Variable O&M ($/MWh) | 20 to 25 | 10 to 20 | 25 to 30 | 10 to 20 |
| Levelized Cost[(2)] $/MWh) | 104 to 146 | 120 to 202 | 121 to 165 | 56 to 99 |
| **Technology Status** | | | | |
| Commercial Status | Commercial | Demonstration | R&D | R&D |
| Installed US Capacity MW) | ~350 | < 1 | 10[(3)] | < 1 |

R&D = Research and Development.
[(1)] Parabolic trough cost estimates have the highest degree of uncertainty for near-term applications. Other technologies assume significant deployment.

[(2)]The low ends of the levelized costs are based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower capacity factors and higher capital and O&M costs.

[(3)]No longer operating.

### *Applications*

The modularity, simple operation, and low maintenance requirements of solar PV make it ideal for distributed, remote, or off-grid applications. Most PV applications are smaller than 1 kW, although larger, utility-scale installations are becoming more prevalent. There are more than 50 PV systems worldwide with capacities greater than 1 MW, including three systems in Germany between 5 and 6.3 MW. The largest system in the United States is Tucson Electric’s Springerville PV plant, with nearly 4.6 MW of capacity.

### *Resource Availability*

Most PV systems installed today are flat plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time. Global insolation on latitude tilt surfaces in Texas ranges from about 4.5 $kW/m^2/day$ in the eastern part of the state up to about 6.5 $kW/m^2/day$ in the western edge of the state, compared with up to 7 $kW/m^2/day$ in the southwestern United States. In north-central Texas, global insolation is generally between 5 and 6 $kW/m^2/day$.

### *Cost and Performance Characteristics*

Table 6-7 presents cost and performance characteristics of a 4 kW residential and a 50 kW commercial fixed-tilt, single crystalline PV system.

Table 6-7
Solar PV Technology Characteristics

| | Residential | Commercial |
|---|---|---|
| **Performance** | | |
| Typical Duty Cycle | As Available, Peaking | As Available, Peaking |
| Net Plant Capacity (kW) | 4 | 50 |
| Capacity Factor (percent) | 18 | 20 |
| **Economics ($2006)** | | |
| Total Project Cost ($/kW) | 8,700 to 13,000 | 7,700 to 9,700 |
| Fixed O&M ($/kW-yr) | 50 | 20 |
| Variable O&M(1) ($/MWh) | 55 | 25 |
| Levelized Cost(2) ($/MWh) | 528 to 732 | 377 to 462 |
| **Technology Status** | | |
| Commercial Status | Commercial | |
| Installed US Capacity (MW) | 365 | |

(1)Includes inverter replacement after 10 years.

(2)The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.

### *Environmental Impacts*

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential for discharge of heavy metals during manufacturing; however, proper monitoring and control can adequately address this issue.

## 6.5 Hydroelectric

### *Operating Principles*

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[5]

### *Applications*

Hydroelectric projects are divided into a number of categories on the basis of their size. Micro hydroelectric projects generate below 100 kW. Systems generating 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems generate between 1.5 MW and 30 MW. Medium hydroelectric projects generate up to 100 MW, and large hydroelectric projects generate more than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

### *Resource Availability*

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve baseloads. Run-of-river projects do not impound the water but, instead, divert a part or all of the current through a turbine to generate electricity. At "run-of-river" projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate annual capacity factor for all hydroelectric plants in the United States has ranged from about 31 percent to 53 percent over the last decade.[6]

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[5] International Energy Agency, 2002.
[6] Based on analysis of reported data from Global Energy Solutions, 2006.

Texas currently has about 189 MW of developed small hydropower resources, with an estimated 326 MW of additional potential capacity.[7]

### *Cost and Performance Characteristics*

Hydroelectric generation is regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Table 6-8 provides ranges for performance and cost estimates for hydroelectric projects for two categories: new projects at undeveloped sites and additions or upgrades to hydroelectric projects at existing sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Table 6-8
Hydroelectric Technology Characteristics

| | New | Incremental |
|---|---|---|
| **Performance** | | |
| Typical Duty Cycle | Varies with Resource | Varies with Resource |
| Net Plant Capacity (MW) | <50 | 1 to 160 |
| Capacity Factor (percent) | 40 to 60 | 40 to 60 |
| **Economics ($2006)** | | |
| Total Project Cost ($/kW) | 2,600 to 4,000 | 700 to 3,000 |
| Fixed O&M ($/kW-yr) | 5 to 25 | 5 to 25 |
| Variable O&M ($/MWh) | 5 to 6 | 4 to 6 |
| Levelized Cost[(1)] ($/MWh) | 45 to 103 | 17 to 82 |
| **Technology Status** | | |
| Commercial Status | Commercial | Commercial |
| Installed US Capacity (MW) | 79,842 | NA |

[(1)]The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs.

[7] Idaho National Engineering and Environmental Laboratory, "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants," January 2006.

### *Environmental Impacts*

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of “fish ladders” to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

# 7.0 RFP Process and Bid Summaries

Brazos Electric issued an RFP for both the short-term and the long-term durations on August 7, 2006. Any Proposal beginning between January 1, 2008, and January 1, 2010, may be for a term as short as 2 years. Any Proposal beginning in 2010 or later must have a minimum term of 10 years. The term of any Proposal could extend up to 20 years or longer, and the term could be linked to the life of a unit. Brazos Electric preferred to purchase power in blocks of 50 MW to 250 MW for conventional plants or system purchases, and blocks as small as 5 MW for LFG and 25 MW for wind and other renewable facilities.

The bids had to be submitted by September 11, 2006, and respondents could respond to the RFP through four different types of proposals. Option No. 1 was for unit contingent power sales from existing or proposed units to be owned by or under the control of the respondent. Option No. 2 was for offers for Brazos Electric to participate in ownership of Respondent's existing units or planned units to be built by the Respondent. Option No. 3 included system power sale by an electric utility or non-utility generator owning multiple units. Option No. 4 was for expressions of interest in joint ownership in a possible Brazos Electric capacity option to be built by Brazos Electric in the future. Responses could be for renewable energy, conventional generating units, and nuclear; however, no nuclear or renewable alternatives were proposed. A total of nine companies provided 15 proposals in response to the RFP. These proposals are summarized collectively in Table 7-1, as well as individually in the following sections.

## 7.1 Short-Term Proposals

In response to the RFP, five short-term proposals were received. The short-term proposals were generally for 2 to 4 years, beginning in 2008. All short-term proposals received were from natural gas fired simple cycle or CC plants, with call options or tolling agreements with guaranteed plant heat rates.

***Note: Sections 7.1.1 through 7.1.5, which provided the names of companies and narrative summaries of the short-term proposals, have been redacted.***

Table 7-1
Bid Summary Table

| | Parent Company | Facility | Offer Type | Term* | Proposal Type | Technology | Fuel Type | Start Year | End Year | Capacity | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ST! | Combination of Facilities | System Sales | ST | Call Option | CC | Natural Gas | 2008 | 2009 | 200 | 140 |
| 2 | ST2 | Combination of Facilities | System Sales | ST | Call Option | CC | Natural Gas | 2008 | 2009 | 200 | 140 |
| 3 | ST3 | Specific Power Plant | Unit Contingent | ST | Call Option | CC | Natural Gas | 2008 | 2012 | 200 | 200 |
| 4 | ST4 | Specific Power Plant | Unit Contingent | ST | Call Option | Unknown | Natural Gas | 2008 | 2010 | 150 | 125 |
| 5 | ST5 | Specific Power Plant | Unit Contingent | ST | Tolling | CC | Natural Gas | 2008 | 2009 | 470 | 470 |
| 6 | LT1 | Specific Power Plant | Unit Contingent | LT | Tolling | CC | Natural Gas | 2009 | 2038 | 525 | 525 |
| 7 | LT2 | Specific Power Plant | Unit Contingent | LT | Tolling Equity Participation | SC PC | PRB Coal | 2011 | 2040 | 250 | 250 |
| 8 | LT3 | Combination of Facilities | System Sales, Firm 24x7 | LT | Call Option | CC | Natural Gas | 2010 | 2029 | 250 | 250 |
| 9 | LT4 | Specific Power Plant | Unit Contingent | LT | Tolling | CT | Natural Gas | 2008 | 2027 | 400 | 400 |
| 10 | LT5 | Specific Power Plant | Unit Contingent | LT | Tolling | CT | Natural Gas | 2008 | 2027 | 200 | 200 |

Table 7-1 (Continued)
Bid Summary Table

| | Parent Company | Facility | Offer Type | Term | Proposal Type | Technology | Fuel Type | Start Year | End Year | Capacity | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | LT6 | Specific Power Plant | Unit Contingent | LT | Tolling Gas | CC | Natural Gas | 2007 | 2016/2026 | 75 | 75 |
| 12 | LT7 | Specific Power Plant | Unit Contingent | LT | Equity Participation | SC PC | Coal Petcoke | 2012 | 2041 | 700 (MW)--Total to be pro rated | |
| 13 | LT8 | Specific Power Plant | Unit Contingent | LT | Call Option | Unknown | Natural Gas | 2011 | 2030 | 500 | 250 |
| 14 | LT9 | Specific Power Plant | Unit Contingent | LT | Call Option | Unknown | Lignite | 2010 | 2030 | 600 | 200 |
| 15 | LT10 | Combination of Facilities | System Sales | LT | Call Option | Unknown | Solid Fuels | 2008 | 2030 | 600 | 200 |

ST - Short-Term
LT - Long-Term

## 7.2 Long-Term Proposals

In response to the RFP, 10 long-term proposals were received. The long-term proposals were generally for 20 to 30 years, beginning in 2008 or later. The long-term proposals received are summarized below.

***Note: Sections 7.2.1 through 7.2.10, which provided the names of companies and narrative summaries of the long-term proposals, have been redacted.***

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# 8.0 Supply-Side Screening

A supply-side screening was performed on each of the self-build alternatives evaluated for the power supply study as well as each of the responses from the RFP process. The supply-side screening considers each alternative's levelized cost at various capacity factors. The levelized cost for each alternative and RFP response is determined on a dollar per MWh basis and includes capital costs, fuel costs, and O&M costs. The levelized cost is calculated to reflect an all-in cost for energy at a given capacity factor and is used to make screening level comparisons of different technologies and proposals. The costs for each self-build alternative were levelized over an evaluation period of 30 years. For the RFP responses, the levelized costs were determined over the term of the proposal.

The alternatives that appear favorable in the supply-side screening will be evaluated further by Brazos Electric using Strategist software. The following sections present the results of the supply-side screening for the RFP responses and the self-build alternatives. A summary of the alternatives that will be considered further in the detailed economic analysis will be developed from these initial screenings.

## 8.1 Screening Assumptions

A number of economic assumptions were used to develop the levelized cost screening curves. These assumptions were used for both the RFP responses and the self-build alternatives. These generic assumptions included fuel price forecasts, interest rate, discount rate, and inflation rate. In addition, a fixed charge rate was developed for the self-build alternatives to allocate the capital cost of the plant over a 30 year period. The FCR assumed was 8.44 percent. The RFP responses provided fixed capacity charges to recover the fixed investment costs for each proposal.

ACES provides fuel price forecasts for Brazos Electric. For the screening analysis the ACES fuel price forecast dated August 11, 2006, for the complete ERCOT system was used. Brazos Electric applied a basis price adjustment for the natural gas prices. Black & Veatch estimated the delivery cost of PRB coal to the North Dallas/Fort Worth area and added this cost to the ACES fuel price forecasts. Lignite was used for the CFB self-build and LT9 proposal. PRB coal was assumed for other coal fired alternatives, and natural gas was assumed for CC and simple cycle options. Table 8-1 presents the fuel price forecasts in nominal dollars used for the screening evaluations.

Table 8-1
Screening Evaluation Fuel Price Forecasts

| Year | Delivered PRB Coal Price ($/MMBtu) | Lignite Coal Price ($/MMBtu) | Natural Gas Price ($/MMBtu) |
|---|---|---|---|
| 2007 | 1.52 | 1.54 | 9.56 |
| 2008 | 1.49 | 1.51 | 9.11 |
| 2009 | 1.45 | 1.47 | 8.59 |
| 2010 | 1.42 | 1.37 | 8.06 |
| 2011 | 1.39 | 1.43 | 7.56 |
| 2012 | 1.41 | 1.48 | 7.17 |
| 2013 | 1.48 | 1.43 | 6.87 |
| 2014 | 1.52 | 1.39 | 6.67 |
| 2015 | 1.53 | 1.38 | 6.55 |
| 2016 | 1.58 | 1.47 | 6.45 |
| 2017 | 1.64 | 1.50 | 6.38 |
| 2018 | 1.75 | 1.55 | 6.33 |
| 2019 | 1.86 | 1.66 | 6.29 |
| 2020 | 1.98 | 1.72 | 6.28 |
| 2021 | 2.04 | 1.79 | 6.45 |
| 2022 | 2.20 | 1.93 | 6.63 |
| 2023 | 2.32 | 2.02 | 6.81 |
| 2024 | 2.45 | 2.02 | 7.00 |
| 2025 | 2.41 | 1.89 | 7.19 |
| 2026 | 2.46 | 1.94 | 7.39 |
| 2027 | 2.51 | 1.99 | 7.59 |
| 2028 | 2.56 | 2.05 | 7.80 |
| 2029 | 2.61 | 2.10 | 8.01 |
| 2030 | 2.67 | 2.16 | 8.23 |
| 2031 | 2.72 | 2.22 | 8.46 |
| 2032 | 2.78 | 2.28 | 8.69 |
| 2033 | 2.84 | 2.34 | 8.93 |
| 2034 | 2.90 | 2.41 | 9.18 |
| 2035 | 2.96 | 2.48 | 9.43 |
| 2036 | 3.03 | 2.54 | 9.69 |
| 2037 | 3.09 | 2.61 | 9.96 |
| 2038 | 3.16 | 2.69 | 10.23 |
| 2039 | 3.23 | 2.76 | 10.51 |
| 2040 | 3.30 | 2.84 | 10.80 |

For the screening evaluations, a debt interest rate of 6 percent and a discount rate of 6 percent were assumed based on Brazos Electric plans to finance its projects with 100 percent tax exempt debt from RUS. In developing forecasts for future costs, an inflation rate of 2.5 percent was assumed. For the RFP responses, an inflation rate of 2.5 percent was also assumed, except for a few short-term proposals that specified a fixed escalation rate.

## 8.2 RFP Long-Term Response Screening

The long-term RFP responses that were evaluated in the screening analysis included PC, CC, and simple cycle technologies. Therefore, both natural gas and coal fuels were proposed. The responses were evaluated at capacity factor increments of 10 percent, to illustrate how the levelized cost of each alternative varies with capacity factor. Long-term responses included the following ***(Company and site names have been redacted)***:

- LT5 200 MW, 20 year offer, GE LMS100 simple cycle.
- LT4 400 MW, 20 year offer, GE LMS100 simple cycle.
- LT6 75 MW, 20 year offer, GE LM2500 CC.
- LT8 500 MW, 20 year offer, Two block GE 7FA CC.
- LT3 250 MW firm energy 7x24 offer.
- LT1 525 MW, 30 year offer, F-Class CC.
- LT1 250 MW, 20 year offer, supercritical PC.
- LT9 200 to 600 MW, 20 to 25 year term, PC (lignite).
- LT10 200 to 400 MW, 20 to 25 year term, system sales.

The results of long-term response screening are summarized in Table 8-2 and shown graphically on Figure 8-1.

For the long-term proposals, the firm LD energy proposals that required must take energy are presented as a single data point at a capacity factor of 80 percent for comparison purposes. The actual take would be 7 days per week, 24 hours per day. In addition, the LT4 and LT5 proposals are presented at capacity factors of 20, 30, and 40 percent only because of expected permit limitations of 4,000 hours per year.

Table 8-2
Levelized Cost Analysis for Long-Term Proposals

| Company | Capacity Factor (%) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 100 | 90 | 80 | 70 | 60 | 50 | 40 | 30 | 20 | 10 |
| LT5 200 MW (2008-2027) | | | | | | | 116.66 | 131.56 | 161.35 | |
| LT4 400 MW (2008-2027) | | | | | | | 107.76 | 119.76 | 143.76 | |
| LT6 75 MW (2007-2026) | 81.32 | 82.52 | 84.03 | 85.97 | 88.56 | 92.17 | 97.60 | 106.65 | 124.75 | 179.04 |
| LT8 500 MW (2011-2031) | 65.52 | 66.73 | 68.24 | 70.18 | 72.76 | 76.39 | 81.82 | 90.87 | 108.97 | 163.29 |
| LT3 250 MW (2010 2029) | | | 67.00 | | | | | | | |
| LT1 500 MW CC (2009-2038) | 67.66 | 68.83 | 70.29 | 72.17 | 74.67 | 78.17 | 83.43 | 92.19 | 109.71 | 162.27 |
| LT2 250 MW Coal (2011-2040) | 50.41 | 53.60 | 57.59 | 62.72 | 69.57 | 79.15 | 93.52 | 117.47 | 165.36 | 309.06 |
| LT9 (2010-2030) | 48.10 | 51.55 | 55.87 | 61.42 | 68.83 | 79.19 | 94.74 | 120.65 | 172.48 | 327.96 |
| LT10 System Sales (2008-2030) | | | 79.57 | | | | | | | |

NA- Not Applicable

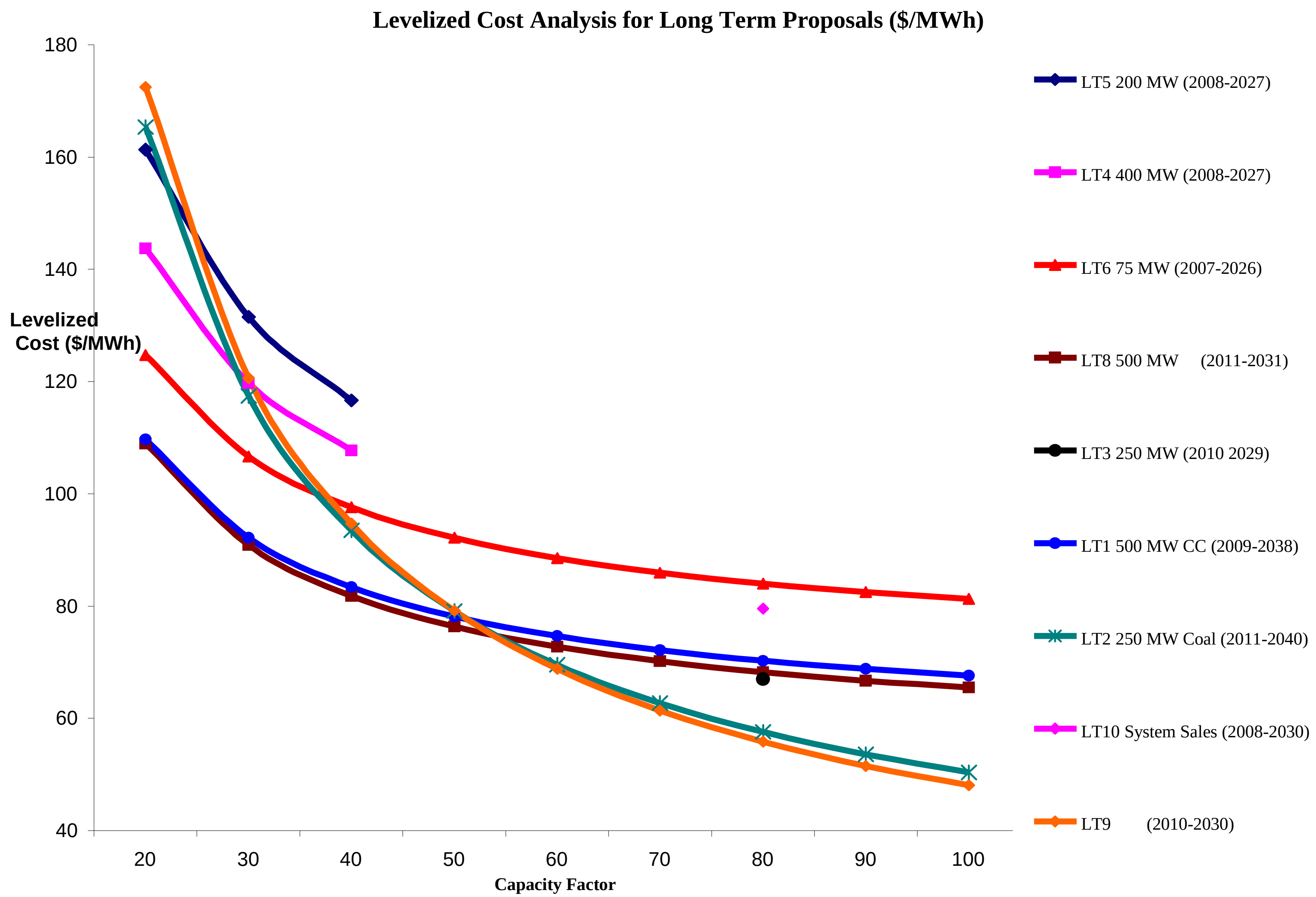


Figure 8-1
Long-Term Proposal Screening Analysis

## 8.3 RFP Short-Term Response Screening

The short-term RFP responses that were evaluated in the screening analysis included CC and simple cycle technologies. Therefore, only natural gas fuels were proposed. The responses were evaluated at capacity factor increments of 10 percent, to illustrate how the levelized cost of each alternative varies with capacity factor. Short-term responses included the following:

- ST5 470 MW, 2 year offer, GE 7FA CC.
- ST1 200 MW, 2 year offer, CC.
- ST2 150 MW, 2 year offer, simple cycle.
- ST3 200 MW, 5 year offer, SWPC 501G CC.
- ST4 150 MW firm energy, 3 year offer, GE 7FA CC.

The results of short-term response screening are summarized in Table 8-3 and shown graphically on Figure 8-2.

## 8.4 Self-Build Alternative Screening

The self-build alternatives that were evaluated in the screening analysis included PC, CFB boiler, IGCC, CC, and simple cycle technologies. The IGCC alternative was assumed to combust PRB coal and utilize Shell quench gasifiers. Therefore, solid and gas fuels were evaluated. The self-build alternatives were evaluated at capacity factor increments of 10 percent to illustrate how the levelized cost of each alternative varies with capacity factor. Self-build alternatives included the following:

- 500 MW PC on PRB coal.
- 500 MW CFB on Texas lignite coal.
- 160 MW GE 7FA simple cycle with and without SCR system.
- 100 MW GE LMS100 simple cycle (SC).
- 90 MW GE LM6000 simple cycle.
- 250 MW 1x1 GE 7FA CC.
- 475 MW 2x1 GE 7FA CC with cooling tower.
- 475 MW 2x1 GE 7FA CC with air-cooled condenser.
- 550 MW IGCC.

Table 8-3
Levelized Cost Analysis for Short-Term Proposals

| Company | Capacity Factor (%) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 10 | 20 | 30 | 40 | 50 | 60 | 70 | 80 | 90 | 100 |
| ST5 | 200.34 | 132.58 | 110.01 | 98.72 | 91.95 | 87.43 | 84.20 | 81.78 | 79.90 | 78.40 |
| ST1 (CC) | 227.36 | 146.88 | 120.06 | 106.64 | 98.60 | 93.23 | 89.40 | 86.52 | 84.29 | 82.50 |
| ST2 (CT) | 147.46 | 121.77 | 113.21 | 108.93 | 106.36 | 104.65 | 103.43 | 102.51 | 101.80 | 101.23 |
| ST3 | 188.27 | 124.14 | 102.77 | 92.08 | 85.66 | 81.39 | 78.34 | 76.04 | 74.26 | 72.84 |
| ST4 | 173.03 | 119.20 | 101.25 | 92.28 | 86.90 | 83.31 | 80.75 | 78.82 | 77.33 | 76.13 |

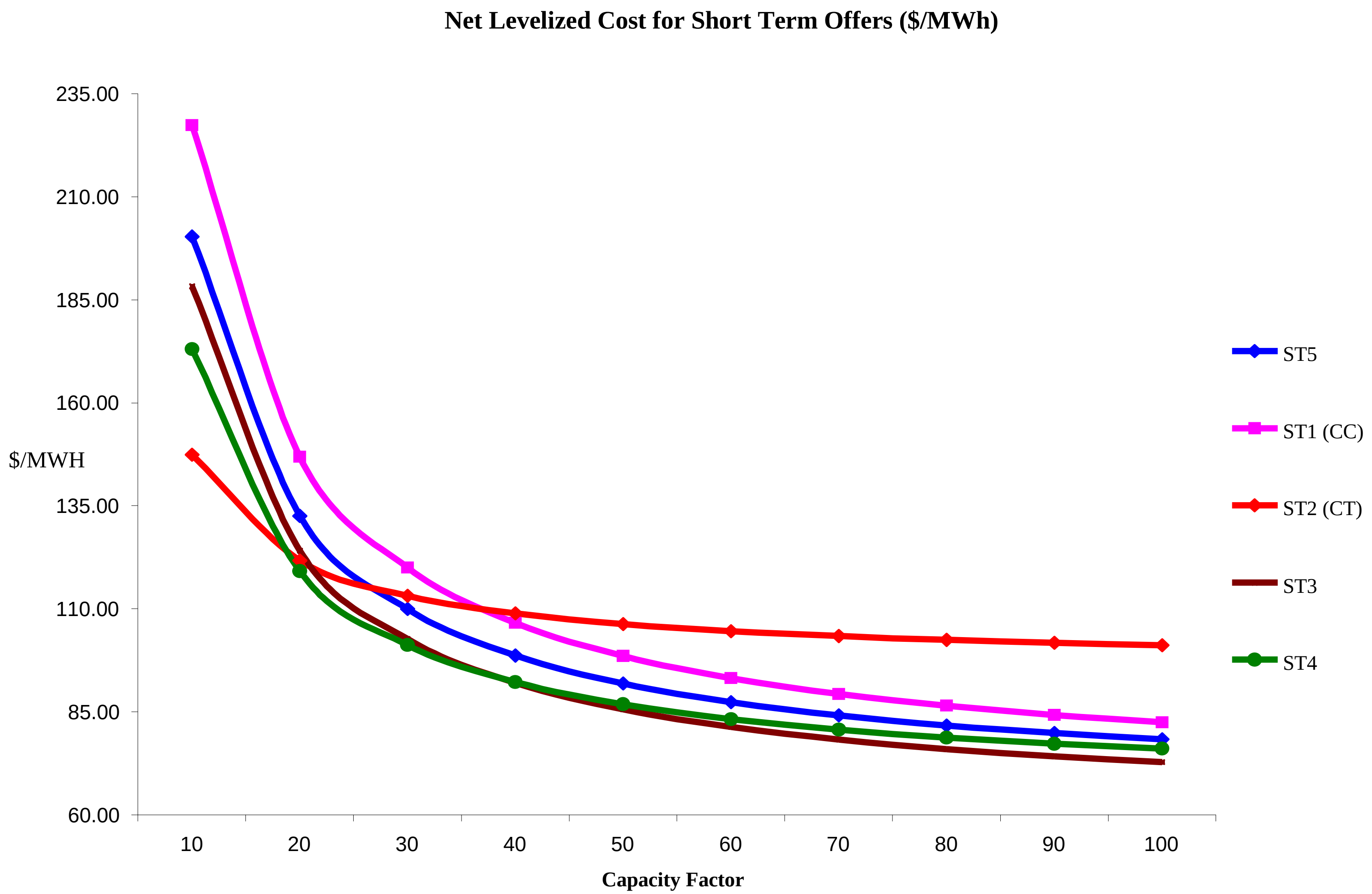


Figure 8-2
Short-Term Proposal Screening Analysis

The results of self-build alternative screening are summarized in Table 8-4 and shown graphically on Figure 8-3.

## 8.5 Summary of Screening Results

As shown in the screening curves presented above, the cost-effectiveness of various plant types and proposals will depend on the expected capacity factors that these plants operate. For the long-term proposals, at capacity factors of approximately 40 percent or less the CC alternatives proposed by LT8 and LT1 appear to have the lowest levelized cost. As capacity factors increase to 50 percent, the LT2 250 MW coal offer becomes comparable to the two CC offers, and at approximately 60 percent capacity factor, the LT2 250 MW coal offer has the lowest levelized cost. At approximately 80 percent capacity factor, the LT2 250 MW coal offer and the LT9 offer have the lowest levelized cost among the long-term proposals. Although the LT10 system sales is price competitive, it is a firm LD energy offer and, thus, has less scheduling flexibility.

For the short-term offers, the ST4 and ST3 offers have the lowest levelized cost for capacity factors in the range of approximately 30 to 80 percent. At a 20 percent capacity factor, the ST2 CT offer is slightly lower than the ST3 offer.

For the self-build alternatives, the 500 MW CFB and PC units have the lowest levelized cost for capacity factors greater than approximately 35 percent. Below 30 percent capacity factors, the three GE 7FA self-build CC alternatives have the lowest levelized cost.

As shown in Table 8-4 and on Figure 8-3, the self-build 2x1 CC at the Jack County site utilizing an air-cooled condenser has a busbar cost that is slightly lower than the generic 2x1 CC utilizing a cooling tower. These two options have similar busbar costs for the following reasons:

- The screening analysis was done at the average ambient temperature of 68° F for all options. At this temperature, the air-cooled performance is not impacted as much as it is for higher ambient temperatures. Figure 8-4 illustrates that at an ambient temperature of 102° F, the air-cooled option has a higher busbar cost than the greenfield 2x1 CC with a cooling tower. The levelized costs are shown in Table 8-5.

Table 8-4
Net Levelized Bus-bar Cost for Self-Build Alternatives ($/MWh)

| Supply-Side Option | Capacity Factor, % | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 100 | 90 | 80 | 70 | 60 | 50 | 40 | 30 | 20 | 10 |
| 500 MW PC on PRB Coal | 40.38. | 42.73 | 45.66 | 49.44 | 54.47 | 61.52 | 72.09 | 89.70 | 124.93 | 230.62 |
| 500 MW CFB on Lignite | 42.22 | 44.32 | 46.95 | 50.32 | 54.82 | 61.12 | 70.57 | 86.32 | 117.83 | 212.33 |
| 156 MW SC GE 7FA Without SCR | 107.50 | 108.06 | 108.75 | 109.65 | 110.84 | 112.50 | 115.00 | 119.16 | 127.49 | 152.48 |
| 155 MW SC GE 7FA With SCR | 109.01 | 109.62 | 110.38 | 111.35 | 112.66 | 114.48 | 117.21 | 121.76 | 130.87 | 158.19 |
| 96 MW LMS 100 Simple Cycle | 82.23 | 83.17 | 84.34 | 85.86 | 87.87 | 90.70 | 94.93 | 101.99 | 116.11 | 158.46 |
| 87 MW LM6000 Simple Cycle | 89.21 | 90.33 | 91.74 | 93.54 | 95.95 | 99.32 | 104.37 | 112.80 | 129.64 | 180.19 |
| 241 MW 1x1 CC GE 7FA | 66.03 | 66.86 | 67.91 | 69.24 | 71.03 | 73.52 | 77.27 | 83.51 | 96.00 | 133.46 |
| 481 MW 2x1 CC GE 7FA with Cooling Tower | 65.11 | 65.86 | 66.80 | 68.01 | 69.62 | 71.88 | 75.27 | 80.91 | 92.20 | 126.07 |
| 472 MW 2x1 CC GE 7FA with Air-Cooled Condenser | 64.85 | 65.61 | 66.57 | 67.80 | 69.44 | 71.73 | 75.17 | 80.91 | 92.38 | 126.80 |
| 550 MW IGCC with PRB Coal | 50.79 | 53.64 | 57.21 | 61.80 | 67.93 | 76.50 | 89.35 | 110.78 | 153.63 | 282.19 |

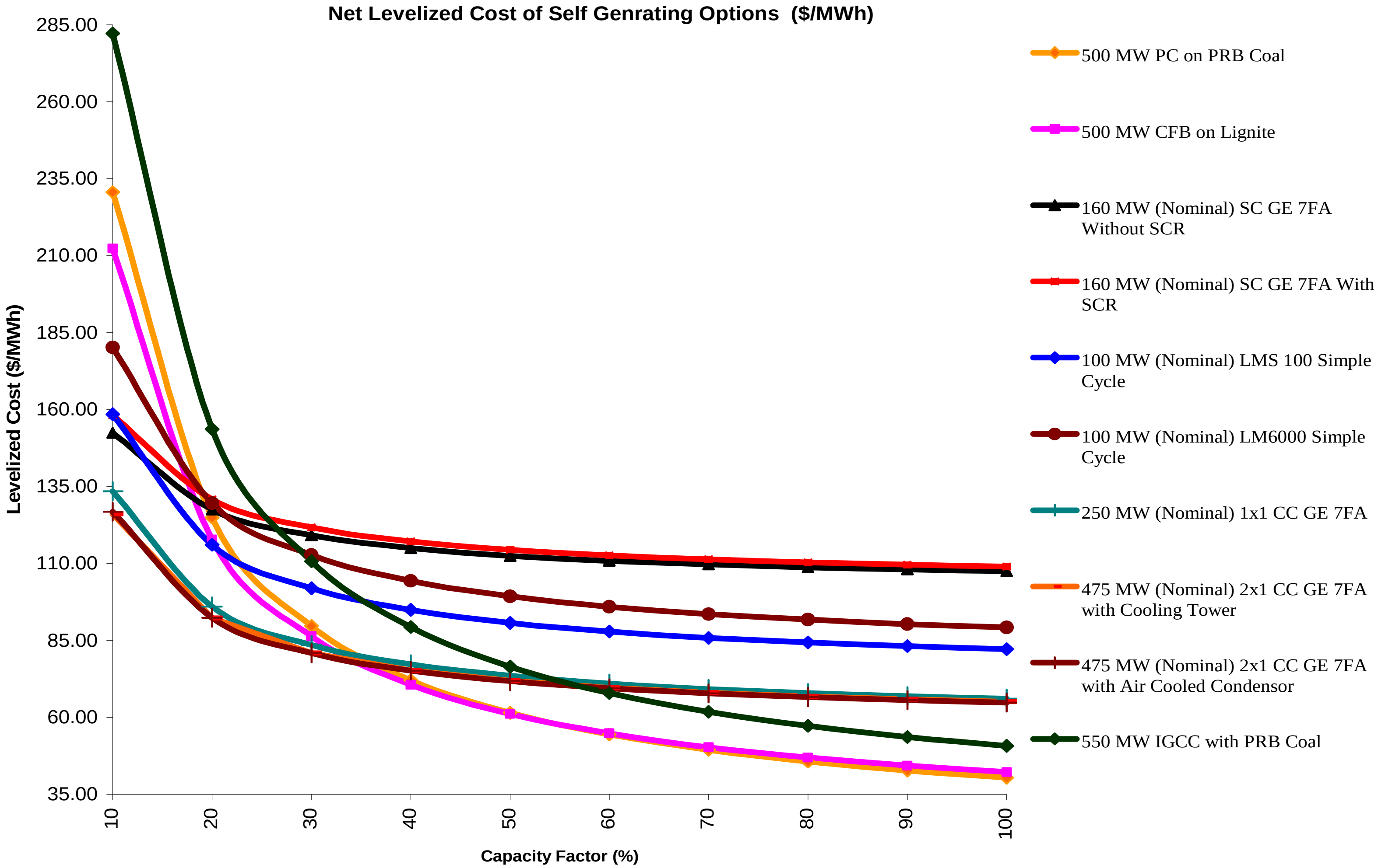


Figure 8-3
Self-Build Screening Analysis

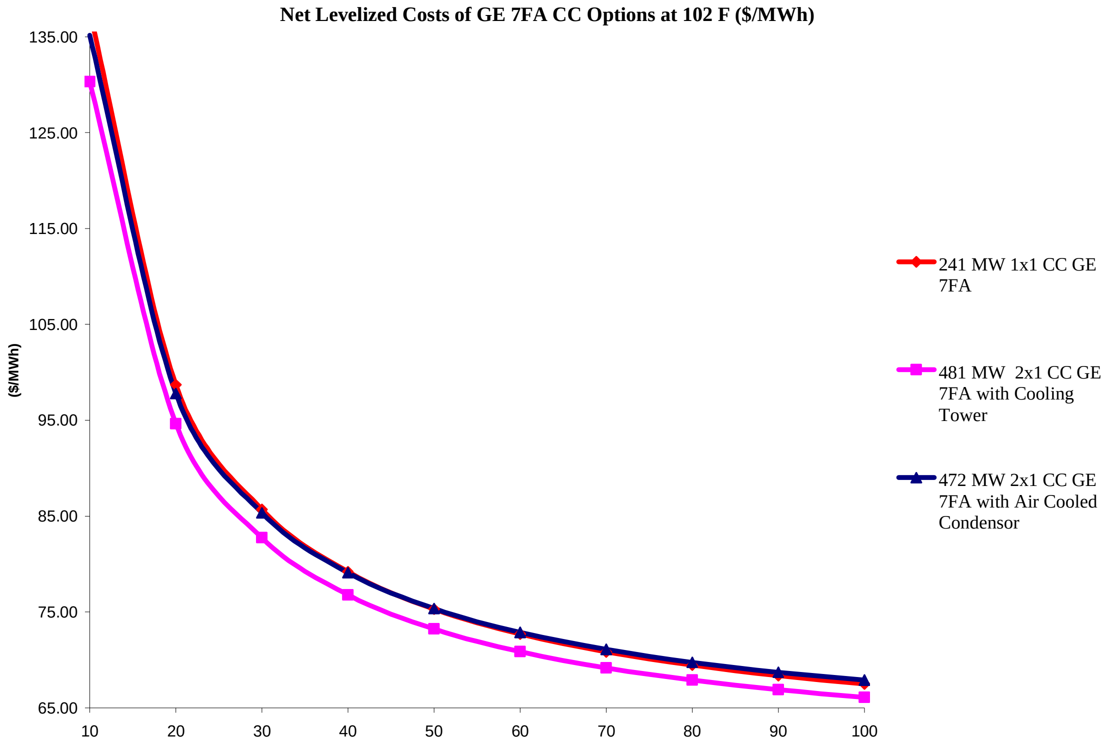


Figure 8-4
Busbar Cost Comparison of Combined Cycle Options at 102 F

Table 8-5
Net Levelized Cost of CC Options at 102° F ($/MWh)

| CC Options | Capacity Factor, % | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 100 | 90 | 80 | 70 | 60 | 50 | 40 | 30 | 20 | 10 |
| 241 MW 1x1 CC GE 7FA | 67.50 | 68.36 | 69.45 | 70.84 | 72.69 | 75.29 | 79.19 | 85.69 | 98.68 | 137.67 |
| 481 MW 2x1 CC GE 7FA with Cooling Tower | 66.10 | 66.89 | 67.88 | 69.16 | 70.86 | 73.23 | 76.80 | 82.75 | 94.64 | 130.31 |
| 472 MW 2x1 CC GE 7FA with Air-Cooled Condenser | 67.89 | 68.72 | 69.76 | 71.09 | 72.87 | 75.36 | 79.10 | 85.33 | 97.79 | 135.17 |

- In developing the cost estimates for the self-build alternatives, Black & Veatch assumed that there would be some savings factored into Jack County 2x1 CC since it is an existing site and an allowance for reuse of existing infrastructure was assumed. This cost savings from the existing site partially offset the higher capital cost for air-cooling.
- The air-cooled CC at Jack County has a lower estimated fixed O&M because of the assumed sharing of some existing Jack County staff and economies of scale from having two blocks at the same site. Additionally, the variable O&M estimate is lower for the 2x1 CC at Jack County because of lower water, water treatment, and waste water treatment costs associated with an air-cooled unit.

# 9.0 Plans for Miller and North Texas Units

Brazos Electric owns and operates two plants in Palo Pinto and Parker counties. The plant in Palo Pinto County is referred to as the R. W. Miller Plant, and the one in Parker County is referred to as the North Texas Plant. The R. W. Miller Plant has five units, three of which are more than 30 years old, and the North Texas Plant has three units, all of which are more than 40 years old. These units are ST units and are operated at very low capacity factors, except for North Texas Unit 3, which has been shut down completely for environmental issues. As part of the Power Supply Study, Black & Veatch evaluated the condition of these existing units to assess their capability for continued operation.

## 9.1 Miller Plant Condition Assessment

The Miller Plant is located on Lake Palo Pinto in Palo Pinto County near Palo Pinto, Texas, about 70 miles west-southwest of Ft. Worth. The plant consists of three steam electric units and two Westinghouse 501D simple cycle CT units. The units fire natural gas as the primary fuel and Units 2, 3, 4 and 5 have fuel oil firing capability for backup service. The total combined nominal capacity of the station is about 611 MW.

Units 1, 2, and 3 were commissioned in 1968, 1972, and 1975, respectively, while Units 4 and 5 were commissioned in 1994. The three old units have STs, while the newer units are gas turbines. All three thermal units use once-through cooling from the adjacent lake and are located in an ozone attainment area. Based on Brazos Electric's historical data, these units have experienced low capacity factors in the last few years, with Unit 1 being in the range of 1 to 2 percent, Unit 2 in the range of 6 to 8 percent, and Unit 3 in the range of 13 to 20 percent. Information on the Miller plants, as received from Brazos Electric, is highlighted in Table 9-1.

Significant technical equipment issues were not identified for all the units except Unit 2 during the data review and brief site walkdown inspection. The units were represented as being capable of continued operation as seasonal units. There are no known significant technical issues that would prevent these units from continuing to be operated in a mode comparable to recent experience. This assumes that safe operational and maintenance practices are continued at the station. The plant manager noted that Unit 2 had a generator rotor issue, which would require about $2 million to repair and replace. This was the only significant technical issue identified during this review.

Table 9-1
Miller Unit Statistics

| | Miller Unit 1 | Miller Unit 2 | Miller Unit 3 | Miller Unit 4 | Miller Unit 5 |
|---|---|---|---|---|---|
| Summer Max Capacity (Net MW) | 75 | 120 | 208 | 104 | 104 |
| Winter Max Capacity (Net MW) | 75 | 120 | 208 | 122 | 122 |
| Minimum Load (Net MW) | 20 | 30 | 38 | 34 | 34 |
| Primary Fuel | Gas | Gas | Gas | Gas | Gas |
| Backup Fuel | N/A | No. 2 Fuel Oil | No. 2 Fuel Oil | No. 2 Fuel Oil | No. 2 Fuel Oil |
| Turbine Type | Steam | Steam | Steam | Gas | Gas |
| Year Installed | 1968 | 1972 | 1975 | 1994 | 1994 |
| Average Heat Rate at Minimum | 13,527 | 11,699 | 12,023 | 15,806 | 15,806 |
| Average Heat Rate at Maximum | 11,205 | 10,181 | 10,375 | 11,766 | 11,766 |
| Max Annual Run Time (h) | | | | 2,500 | 2,500 |
| Cold Startup Fuel Consumption (MBtu) | 970 | 940 | 1,320 | 200 | 200 |
| Hot Startup Fuel consumption (MBtu) | 400 | 325 | 420 | 200 | 200 |
| Minimum Runtime (h) | 4 | 4 | 4 | 2 | 2 |
| Minimum Downtime (h) | 8 | 8 | 8 | 2 | 2 |

In the event that significant issues develop in the future on any of these units that impair safe, reliable operation of the units in accordance with environmental requirements, an evaluation of the costs for repairs, upgrades, or refurbishments needed for life extension and safe operation of the unit should be completed.

Based on the information provided by Brazos Electric, the decision to retire the units or continue to operate the units in a mode comparable to recent experience does not appear to be a technical decision but rather one of economics.

## 9.2 Breakeven Screening Curve for R. W. Miller Units

In order to evaluate the economic considerations that would influence the decision on the three old units of the R. W. Miller Plant, (Units 1 through 3), Black & Veatch performed busbar analyses of the existing units and compared them with the proposed new simple cycle alternatives, namely, the LMS 100 unit, LM6000 unit, and the GE 7FA units. Two different scenarios were evaluated. In the first scenario, no capital expenditures were considered for the R. W. Miller units as these units are existing operational units. In the second scenario, $15 million of capital expenditure was assumed for the units, in order to evaluate if it would be economically viable to invest additional capital in these units.

By comparing the R. W. Miller units with the proposed new alternatives, Black & Veatch established the capacity factor at which, operating the R. W. Miller units becomes uneconomical. The busbar curves for the two different scenarios are presented on Figures 9-1 and 9-2.

The busbar analysis was done using the heat rates provided by Brazos Electric and operating data obtained from Energy Velocity database. The information obtained from Energy Velocity database is presented in Table 9-2. The economic parameters were the same as those considered in the busbar analysis of the self-build alternatives, presented in Section 8.0. The natural gas price forecast was also the same as considered in evaluating the self-build alternatives in Section 8.0.

Based on the levelized cost analysis as shown on Figure 9-1, it can be seen that the R. W. Miller Unit 1 becomes uneconomical when the capacity factor is about 50 percent, assuming that there is no capital expenditure involved. This break-even point goes down to about 30 percent when the $15 million capital expenditure is taken into account as shown on Figure 9-2. In both instances, the proposed new LMS 100 unit becomes economical at capacity factors greater than the break-even point, and hence, the R. W. Miller Unit 1 should be replaced by the LMS 100 unit if the capacity factor for the unit regularly exceeds the above mentioned values. However, the R. W. Miller Unit 1 is more economical than building the other new simple cycle alternatives.

## 9.3 North Texas Plant Condition Assessment

The North Texas Plant is located on Lake Weatherford in Parker County near Weatherford, Texas, about 30 miles west of Ft. Worth. The plant consists of three gas fired, steam electric units for a combined nominal capacity of about 75 MW. Based on the Westinghouse heat balances, Units 1 and 2 are rated at 15 MW and Unit 3 is rated at 33 MW. According to Brazos Electric's data, which is presented in Table 9-3, Units 1, 2, and 3 are capable of 18 MW, 18 MW, and 39 MW respectively. The units are capable of firing either natural gas or fuel oil. Units 1 and 2 were commissioned in 1957 and 1958, respectively, while Unit 3 was commissioned in 1962.

All three units use once-through cooling from Lake Weatherford. The plant is located in an ozone nonattainment area. According to the Burns & McDonnell (B&M) report, dated March 2003, the station has a limitation in total capacity factor (approximately 12 percent) due to contractual water usage limitations from the lake.

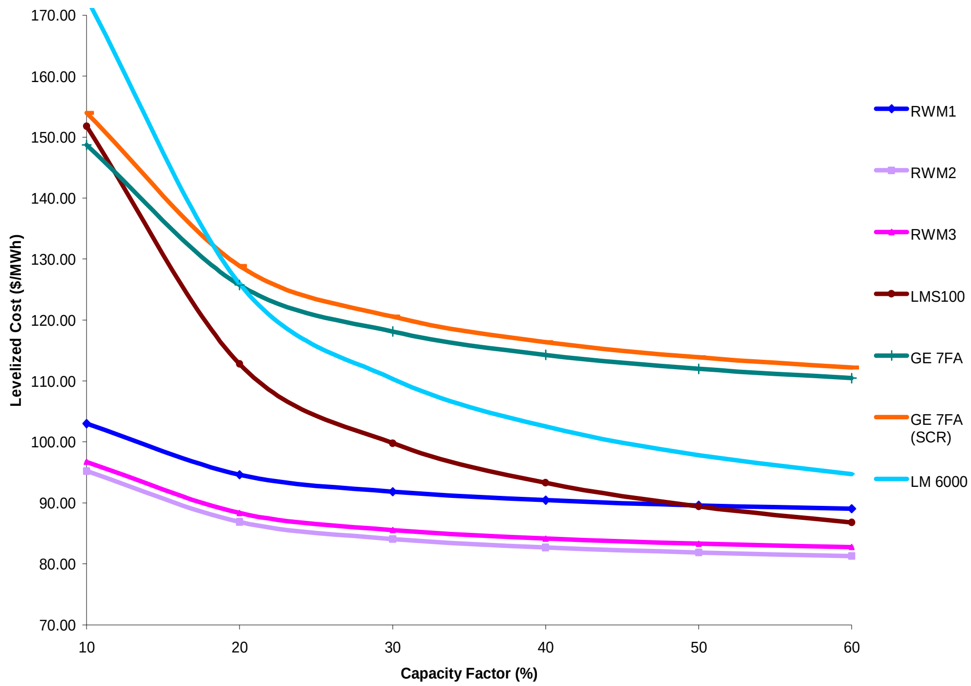


Figure 9-1
Comparison of Levelized Cost of Operating R. W. Miller Units 1 through 3 with New Simple Cycle Alternatives (Without Capital Expenditure)

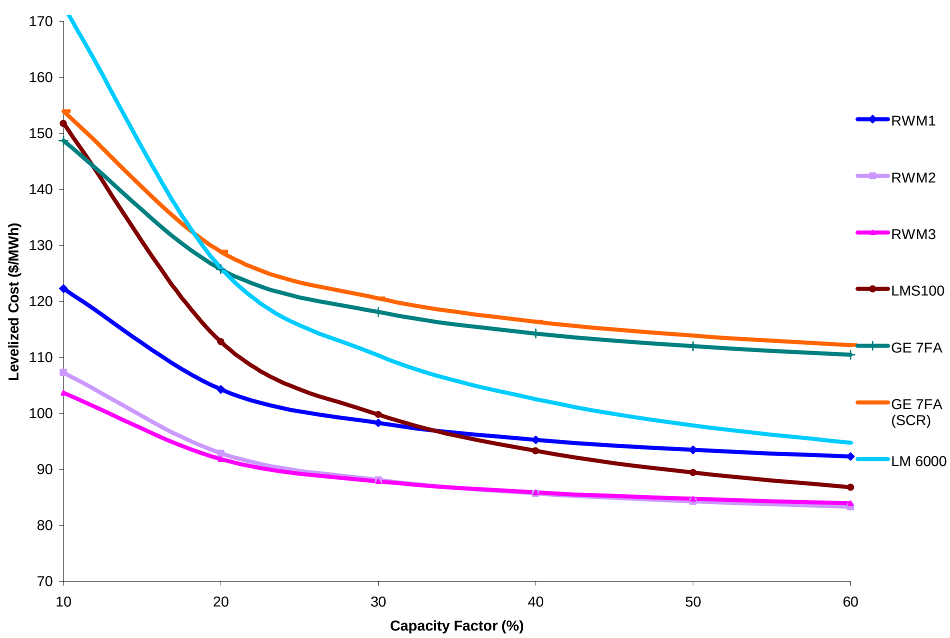


Figure 9-2
Comparison of Levelized Cost of Operating R. W. Miller Units 1 through 3 with New Simple Cycle Alternatives (With Capital Expenditure)

Table 9-2
Operating Data of R. W. Miller Units

| Plant Name | Unit | Prime Mover | Primary Fuel | Variable O&M Cost $/MWh | Fixed O&M Cost $/kW-yr |
|---|---|---|---|---|---|
| R W Miller | 1 | ST | Natural Gas | 0.99 | 11.13 |
| R W Miller | 2 | ST | Natural Gas | 0.99 | 11.13 |
| R W Miller | 3 | ST | Natural Gas | 0.99 | 11.13 |

Table 9-3
North Texas Units Statistics

| | North Texas Unit 1 | North Texas Unit 2 | North Texas Unit 3 |
|---|---|---|---|
| Summer Max Capacity (Net MW) | 18 | 18 | 39.5 |
| Winter Max Capacity (Net MW) | 18 | 18 | 39.5 |
| Minimum Load (Net MW) | 2 | 2 | 4 |
| Primary Fuel | Gas | Gas | Gas |
| Backup Fuel | No. 2 Fuel Oil | No. 2 Fuel Oil | No. 2 Fuel Oil |
| Turbine Type | Steam | Steam | Steam |
| Year Installed | 1958 | 1958 | 1963 |
| Average Heat Rate at Minimum | 16,201 | 14,650 | 12,784 |
| Average Heat Rate at Maximum | 13,619 | 13,334 | 11,955 |
| Normal Ramp Rate (MW/min) | 1/5 | 1/5 | 1/4 |
| Minimum Runtime (h) | 4 | 4 | 4 |
| Minimum Downtime (h) | 8 | 8 | 8 |

Based on Brazos Electric's historical data, the last year of significant operations for North Texas Units 1, 2, and 3 was 2000. During 2000, Units 1, 2, and 3 had capacity factors of 4.17 percent, 3.71 percent, and 6.25 percent, respectively. Based on current operations forecast, these units are expected to experience limited service hours in the future with capacity factors ranging from 1 to 7 percent.

A Remaining Life Assessment report, prepared by B&M in March of 2003, presents information for use by Brazos Electric in evaluating life extension, long-term shutdown (mothballing), decommissioning of the units as well as repowering of Unit 3. This report provides an estimated cost of life extension for the station of about $11.8 million; however, the report does not provide details of the types of refurbishment projects required to extend the life of the units. B&M recommended inspections and nondestructive examination (NDE) to determine the actual refurbishment program.

Significant technical equipment issues were not identified during the data review and brief site walkdown inspection. The units were represented as being capable of continued operation as seasonal units with limitations due to air emissions and water consumption. There are no known significant issues that would prevent these units from continuing to be operated as seasonal or cyclic units similar to recent experience. This assumes that safe operational and maintenance practices are continued at the station.

Due to the age of these units, their cyclic, seasonal duty, and the minimal maintenance they are likely to receive based on their expected duty, it is probable that the units will experience a higher forced outage rate in the future as compared to past experience. In the event that significant issues develop in the future on any of these units that impair safe reliable operation of the units in accordance with environmental requirements, an evaluation of the costs for repairs, upgrades, or refurbishments needed for life extension and safe operation of the unit should be completed.

Based on the information provided by Brazos Electric, the decision to retire the units or continue operations in a mode comparable to recent experience does not appear to be a technical decision but rather one of economics. Information on the Miller Plants as received from Brazos Electric is highlighted in Table 9-3.

## 9.4 Breakeven Screening Curve for North Texas Units

In order to evaluate the economic considerations that would influence the decision on the two operating units of the North Texas Plant, Black & Veatch performed busbar analyses of the existing units and compared them with the proposed new simple cycle alternatives, namely, the LMS 100 unit, LM6000 unit, and the GE 7FA units. Two different scenarios were evaluated. In the first scenario, no capital expenditures were considered for the North Texas units as these units are existing operational units. In the second scenario, $15 million of capital expenditure was assumed for the units, in order to evaluate if it would be economically viable to make further capital expenditures. By comparing the North Texas units with the proposed new alternatives, Black & Veatch established the capacity factor at which these units become uneconomical. The busbar curves for the two different scenarios are presented on Figures 9-3 and 9-4.

The busbar analysis was done using the heat rates provided by Brazos Electric and operating data obtained from Energy Velocity database, and presented in Table 9-4. Unit 3 data is not presented, since the unit has been shut down due to environmental issues.

Based on the levelized cost analysis, North Texas Units 1 and 2 become uneconomical when the capacity factor is about 17 percent, assuming that there is no capital expenditure involved. At that point, the proposed new LMS 100 unit becomes economical. Additionally the proposed LM6000 unit becomes economical at capacity factors greater than 20 percent. Hence, the new LMS 100 unit should replace the North Texas Units 1 and 2 if the capacity factors for the existing units regularly exceed the above mentioned value.

When capital expenditures are considered, both the units become uneconomical compared to all the new simple cycle alternatives. As such, new units should replace these units when new significant capital expenditures are required.

## 9.5 Conclusion

Based on the findings, Black & Veatch concluded that the North Texas and R. W. Miller units should continue to be operated as they have been assuming the capacity factors in the future are similar to recent historical levels of operation. In addition, if environmental pollution upgrades are required; major plant overhauls or capital expenditures are required; or capacity factors increase beyond 17 percent for the North Texas Units and 50 percent for R. W. Miller Unit 1, then Brazos Electric should consider retiring these units and installing newer more efficient capacity.

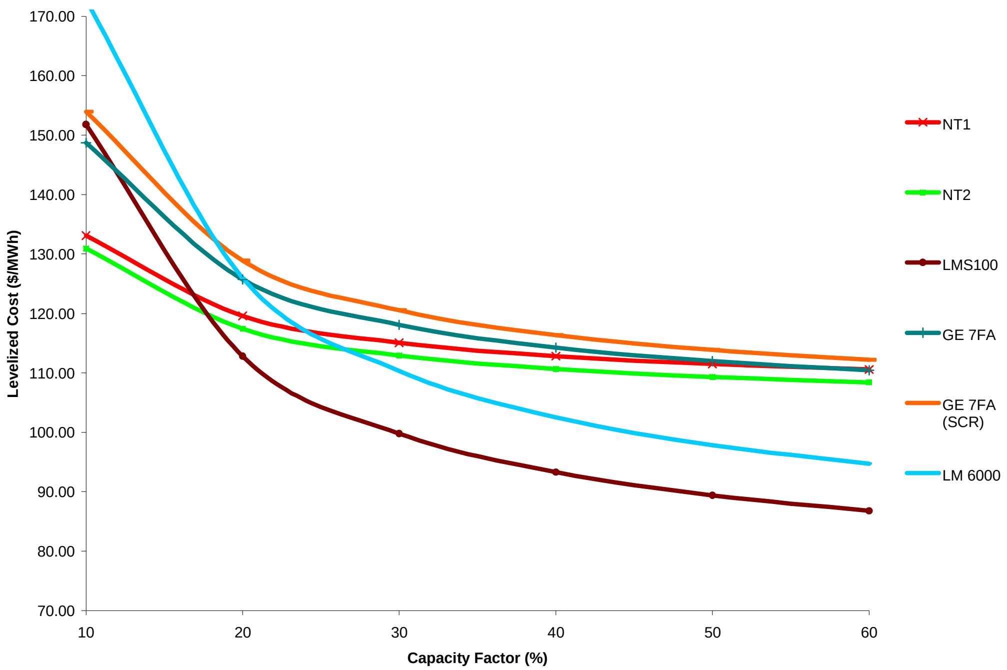


Figure 9-3
Comparison of Levelized Cost of Operating North Texas Units 1 through 3 with New Simple Cycle Alternatives (Without Capital Expenditure)

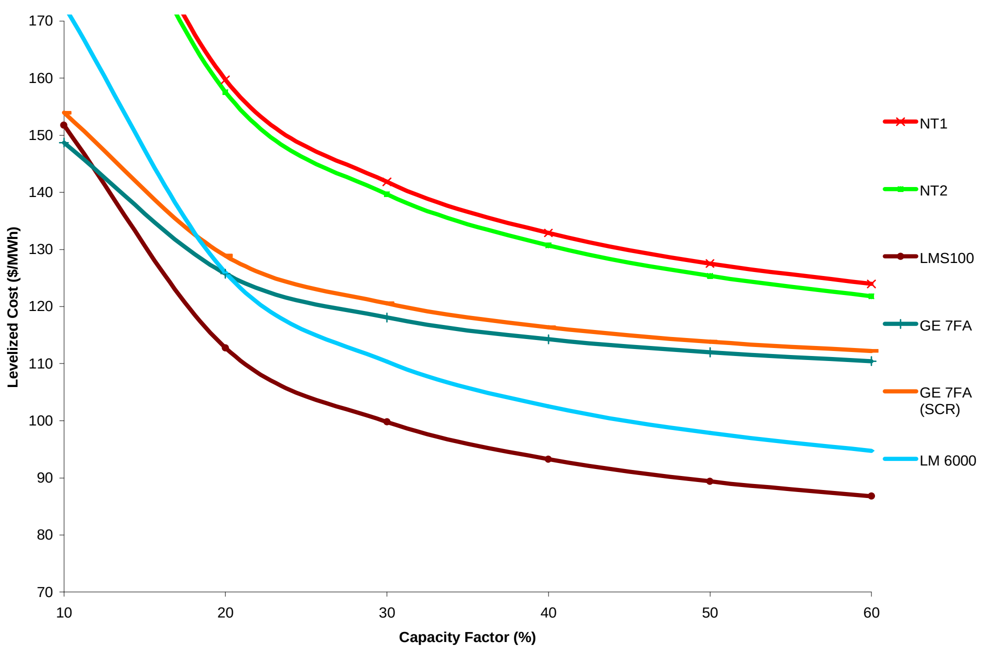


Figure 9-4
Comparison of Levelized Cost of Operating North Texas Units 1 through 3 with New Simple Cycle Alternatives (With Capital Expenditure)

Table 9-4
Operating Data of North Texas Units

| Plant Name | Unit | Prime Mover | Primary Fuel | Variable O&M Cost $/MWh | Fixed O&M Cost $/kW-yr |
|---|---|---|---|---|---|
| North Texas | 1 | ST | Natural Gas | 2.14 | 17.96 |
| North Texas | 2 | ST | Natural Gas | 2.14 | 17.96 |

# 10.0 New Energy Strategist and Proview Analysis

A detailed economic analysis was performed to determine the least-cost capacity expansion plan to meet Brazos Electric's forecast capacity requirements during the planning horizon. This section presents the assumptions and methodology used in the economic analysis, as well as the results of the base case analysis.

A capacity expansion optimization computer model was used by Brazos Electric to evaluate combinations of resources available to Brazos Electric to meet future load requirements. Black & Veatch reviewed the analysis performed by Brazos Electric. Multiple combinations of future resource additions were selected by the model to meet forecast capacity requirements. The resources evaluated include the self-build alternatives described in Section 5.0 and the alternatives that passed the supply-side screening described in Section 8.0.

As presented in Section 3.0, a forecast of peak demand and NEL was provided for Brazos Electric's system through 2022. For evaluation purposes, loads are held constant beyond 2022. Brazos Electric's forecast capacity requirements are developed as shown in Section 4.0 using the peak demand forecast, 12.5 percent reserve requirement, and existing generating resources. Brazos Electric's share of the Hugo 2 PC unit is included as a committed unit in 2012. Additionally, it was assumed the North Texas 3 unit would not operate during the study period due to permit emission limitations.

The economic analysis described herein compares the economics of five capacity expansion plans that result in the lowest cumulative present worth costs. As explained later in this section, two of the final five capacity expansion plans include two long-term purchase resources evaluated in Section 5.0 along with self-build resources. The remaining three capacity expansion plans include only self-build resources.

## 10.1 Expansion Planning and Production Costing Methodology

The supply-side evaluations of generating resource alternatives were performed using New Energy's Strategist and Proview$^{TM}$ software (Strategist), an optimal generation expansion and production cost model licensed by Brazos Electric. Brazos Electric staff has utilized Strategist in previous power supply studies.

Strategist evaluates all combinations of generating unit alternatives and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 30 year period from 2006 through 2035.

Brazos Electric has and continues to utilize market priced forward transactions to meet its peak demand requirement. ACES, which is a wholesale energy trading and risk management firm, provided projected prices for these forward transactions. Brazos Electric modeled these transactions as 7x16 (available 7 days a week for the 16 peak period hours) dispatched on a daily basis. Thus, Strategist dispatches the transaction if it is economical to do so for a 16 hour block, or not at all. After making a number of preliminary modeling runs with Strategist, Brazos Electric made the decision to include a set level of assumed forward purchases in all of the capacity expansion plans. Thus, Brazos Electric has included 900 MW of forward purchases in 2009 and 750 MW of forward purchases in 2010 and thereafter. Brazos Electric then used Strategist to develop capacity expansion plans in which owned and purchased capacity (including the forwards) total or slightly exceed the projected peak demand.

Strategist utilizes emergency energy purchases in those times that the energy requirement exceeds the energy capability of the generating resources due to forced outages. In any given year, emergency energy purchases represent less than 0.04 percent of the total annual energy requirement. Emergency energy purchases are priced at a constant $300 per MWh throughout the study period, which Black & Veatch considers appropriate for modeling purposes.

Strategist estimates annual production costs for each expansion plan and ranks the plans from lowest to highest cumulative present worth cost. Strategist simulates the operation of a power supply system over a specified planning period by economically dispatching available resources to meet the projected capacity and energy requirement. Strategist includes variable O&M and fuel costs when determining the dispatch order for available generating resources.

Required inputs include the performance characteristics of generating units, fuel costs, fixed and variable O&M costs of generating units, emission rates and costs for each generating unit, demand and energy charges for purchase power resources, capital costs for future resource additions, system load profile, and projected capacity requirements including reserves.

Strategist summarizes each resource's operating characteristics for every year of the planning horizon. These characteristics include, among others, each resource's annual generation, fuel consumption, fuel cost, emissions cost, and variable O&M costs. Fixed O&M costs were included separately for new unit additions. Typically, fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another and not included in production cost modeling. However, Brazos Electric has included total O&M costs (including fixed O&M costs) for existing units. These costs were applied across all plans. Annual capacity charges for Brazos

Electric's existing and future power purchases were included. The cumulative present worth cost (CPWC) of each expansion plan was calculated based on projected total annual costs.

Brazos Electric provided the operating and cost data (including emission rates) for its existing resources. Black & Veatch provided the operating and cost data for the future self-build generation alternatives. Operating and cost data for the alternatives bid to Brazos Electric in response to the RFP (refer to Section 7.0) were taken from the bids. ACES provided cost forecasts used as the basis for forward transactions, economy purchases, fuel costs, and emission allowance costs. Emission allowance costs for both $NO_X$ and $SO_2$ are included in the economic evaluation.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M, variable O&M, emissions, and levelized capital) for each year of the planning period and discounts each back to 2006 at the present worth discount rate of 6.0 percent. These annual present worth costs were then summed over the 2006 through 2035 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

## 10.2 Capacity Expansion Plans

The previous section described the assumptions and methodology that were used to select least-cost capacity expansion plans for Brazos Electric. Strategist was used to estimate the total annual system costs and to establish the CPWC associated with each expansion plan. The advantage of using a program such as Strategist is that the CPWCs for a large number of plans are developed and the program then ranks the expansion plans from lowest to highest CPWC.

The self-build alternatives included in the five base capacity expansion plans chosen for presentation by Brazos Electric are shown in Table 10-1. Due to the lead time to develop any self-build alternative, no new self-build options are included prior to 2009. From 2006 through 2008, each plan is identical and relies on market-based purchases to meet projected demand and energy requirements. Three of the capacity expansion plans include only self-build resource additions. Two of the capacity expansion plans include two PPAs identified in Section 7.0 as low cost PPAs. The LT9 PPA provides 250 MW of capacity annually from 2010 through 2029. The LT2 PPA provides 250 MW of capacity annually from 2011 through 2044.

Table 10-1
Capacity Expansion Plan Resource Additions

| | Plan 1 | | Plan 2 | | Plan 3 | | PPA 1 | | PPA 2 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | Resource | MW | Resource | MW | Resource | MW | Resource | MW |
| 2009 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 |
| 2010 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 |
| 2011 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | | | | |
| 2012 | | | | | | | | | | |
| 2013 | | | | | | | | | | |
| 2014 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 |
| 2015 | | | | | | | | | | |
| 2016 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 | SC PC PRB | 500.0 |
| 2017 | CBF Lignite | 250.0 | SC PC PRB | 500.0 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | CBF Lignite | 250.0 |
| 2018 | SC 7FA w/o SCR | 154.8 | | | 1x1 7FA CC (Johnson) | 240.6 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 |
| 2019 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 |
| 2020 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | SC 7FA w/o SCR | 154.8 | 1x1 7FA CC (Johnson) | 240.6 | SC 7FA w/o SCR | 154.8 |
| 2021 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 |
| 2022 | 1x1 7FA CC (Johnson County) | 240.6 | SC 7FA w/o SCR | 154.8 | Two SC 7FA w/o SCR | 309.6 | 2x1 7FA CC (GF) | 481.3 | 2x1 7FA CC (GF) | 481.3 |

## 10.3 Results of the Economic Analysis

The CPWC for the five base capacity expansion plans are presented in Table 10-2.

Table 10-2
Summary of CPWC of Base Capacity Expansion Plans

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 18,247,906 | 1 |
| Plan PPA 2 | 18,260,223 | 2 |
| Plan 1 | 18,489,723 | 3 |
| Plan 2 | 18,495,250 | 4 |
| Plan 3 | 18,508,348 | 5 |

# 11.0 Sensitivity Analyses and Risk Mitigation Strategies

The results of the base detailed economic analysis were presented in Section 10.0. This section presents the results of a number of sensitivity analyses performed by Brazos Electric. The sensitivities described in this section reflect changes to input assumptions including capital costs, load forecast, market power and gas costs, coal prices, and $NO_x$ and $SO_2$ emission costs. In addition, sensitivities were performed in which additional emission costs were added to reflect potential future regulation of $CO_2$ emissions. For purposes of this analysis, Brazos Electric did not re-optimize the capacity expansion plans based on the changed parameters, which is consistent with Black & Veatch's expectations for sensitivity analyses. Thus, the results in this section represent estimated costs for the five base capacity expansion plans presented in Section 10.0 assuming a particular input assumption is changed but the capacity expansion plan remains as originally projected.

## 11.1 High Capital Costs

In the high capital cost sensitivity, the capital costs for future generating resources were increased by 20 percent. Considering an increase in capital costs helps capture uncertainty related to the future costs of material, labor, and equipment. The CPWC for the five base capacity expansion plans are presented in Table 11-1. The order that the five plans are presented in Table 11-1 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the higher capital costs can be seen in the column labeled Rank.

Table 11-1
Summary of CPWC of Base Capacity Expansion Plans
High Capital Costs

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 18,776,316 | 1 |
| Plan PPA 2 | 18,828,098 | 2 |
| Plan 1 | 19,102,114 | 4 |
| Plan 2 | 19,165,938 | 5 |
| Plan 3 | 19,079,377 | 3 |

## 11.2 High Load and Energy Forecast

In the high load and energy forecast sensitivity, the econometric energy forecast was regenerated assuming a stronger economy and more severe weather than the base forecast. As in the baseload forecast, the peak demand is then estimated based on the revised energy forecast, system losses, and a typical hourly load pattern. Load and energy growth sensitivities are important analyses that help to demonstrate the robustness of future capacity additions. The CPWC for the five base capacity expansion plans are presented in Table 11-2. The order that the five plans are presented in Table 11-2 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the higher load and energy forecast can be seen in the column labeled Rank.

Table 11-2
Summary of CPWC of Base Capacity Expansion Plans
High Load and Energy Forecast

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 18,866,113 | 1 |
| Plan PPA 2 | 18,871,622 | 2 |
| Plan 1 | 19,112,416 | 3 |
| Plan 2 | 19,114,940 | 4 |
| Plan 3 | 19,135,758 | 5 |

## 11.3 Low Load and Energy Forecast

In the low load and energy forecast sensitivity, the econometric energy forecast was regenerated assuming a weaker economy and less severe weather than the base forecast. As in the baseload forecast, the peak demand is then estimated based on the revised energy forecast, system losses, and a typical hourly load pattern. Load and energy growth sensitivities are important analyses that help to demonstrate the robustness of future capacity additions. The CPWC for the five base capacity expansion plans are presented in Table 11-3. The order that the five plans are presented in Table 11-3 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower load and energy forecast can be seen in the column labeled Rank.

Table 11-3
Summary of CPWC of Base Capacity Expansion Plans
Low Load and Energy Forecast

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 17,256,688 | 1 |
| Plan PPA 2 | 17,281,433 | 2 |
| Plan 1 | 17,469,243 | 3 |
| Plan 2 | 17,490,747 | 5 |
| Plan 3 | 17,476,286 | 4 |

## 11.4 High Purchase Power and Natural Gas Prices

In the high purchase power and natural gas prices sensitivity, the purchase power and natural gas prices were increased by 25 percent. Purchase power prices are increased in this sensitivity to reflect the assumption that purchase power costs are more directly tied to natural gas prices than the price of other fuels. Considering an increase in purchase power and natural gas prices helps capture uncertainty related to the future price of natural gas. The CPWC for the five base capacity expansion plans are presented in Table 11-4. The order that the five plans are presented in Table 11-4 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the higher purchase power and natural gas prices forecast can be seen in the column labeled Rank.

Table 11-4
Summary of CPWC of Base Capacity Expansion Plans
High Purchase Power and Natural Gas Prices

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 20,023,254 | 2 |
| Plan PPA 2 | 19,908,374 | 1 |
| Plan 1 | 20,596,062 | 4 |
| Plan 2 | 20,470,016 | 3 |
| Plan 3 | 20,750,660 | 5 |

## 11.5 Low Purchase Power and Natural Gas Prices

In the low purchase power and natural gas prices sensitivity, the purchase power and natural gas prices were decreased by 25 percent. Purchase power prices are decreased in this sensitivity to reflect the assumption that purchase power costs are more directly tied to natural gas prices than the price of other fuels. Considering a decrease in purchase power and natural gas prices helps capture uncertainty related to the future price of natural gas. The CPWC for the five base capacity expansion plans are presented in Table 11-5. The order that the five plans are presented in Table 11-5 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower purchase power and natural gas prices forecast can be seen in the column labeled Rank.

Table 11-5
Summary of CPWC of Base Capacity Expansion Plans
Low Purchase Power and Natural Gas Prices

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 16,471,345 | 3 |
| Plan PPA 2 | 16,601,402 | 5 |
| Plan 1 | 16,376,128 | 2 |
| Plan 2 | 16,514,569 | 4 |
| Plan 3 | 16,260,569 | 1 |

## 11.6 High Coal Prices

In the high coal prices sensitivity, coal prices were increased by 25 percent. Considering an increase in coal prices helps capture uncertainty related to the future price of coal. The CPWC for the five base capacity expansion plans are presented in Table 11-6. The order that the five plans are presented in Table 11-6 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the higher coal price forecast can be seen in the column labeled Rank.

## 11.7 Low Coal Prices

In the low coal prices sensitivity, coal prices were decreased by 25 percent. Considering a decrease in coal prices helps capture uncertainty related to the future price of coal. The CPWC for the five base capacity expansion plans are presented in Table 11-7. The order that the five plans are presented in Table 11-7 is the same as the

Table 11-6
Summary of CPWC of Base Capacity Expansion Plans
High Coal Prices

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 18,737,693 | 1 |
| Plan PPA 2 | 18,803,253 | 2 |
| Plan 1 | 18,941,491 | 4 |
| Plan 2 | 19,006,256 | 5 |
| Plan 3 | 18,902,495 | 3 |

Table 11-7
Summary of CPWC of Base Capacity Expansion Plans
Low Coal Prices

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 17,758,369 | 2 |
| Plan PPA 2 | 17,714,850 | 1 |
| Plan 1 | 18,038,627 | 4 |
| Plan 2 | 17,984,126 | 3 |
| Plan 3 | 18,114,464 | 5 |

order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower coal price forecast can be seen in the column labeled Rank.

## 11.8 High Emission Costs

In the high emission costs sensitivity, $NO_x$ and $SO_2$ emission costs were increased by 25 percent. Considering an increase in emission costs helps capture uncertainty related to the future price of controlling $NO_x$ and $SO_2$ emissions. The CPWC for the five base capacity expansion plans are presented in Table 11-8. The order that the five plans are presented in Table 11-8 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the higher emission costs can be seen in the column labeled Rank.

Table 11-8
Summary of CPWC of Base Capacity Expansion Plans
High Emission Costs

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 18,384,214 | 1 |
| Plan PPA 2 | 18,405,690 | 2 |
| Plan 1 | 18,627,683 | 3 |
| Plan 2 | 18,637,329 | 5 |
| Plan 3 | 18,637,326 | 4 |

## 11.9 Low Emission Costs

In the low emission costs sensitivity, $NO_x$ and $SO_2$ emission costs were decreased by 25 percent. Considering a decrease in emission costs helps capture uncertainty related to the future price of controlling $NO_x$ and $SO_2$ emissions. The CPWC for the five base capacity expansion plans are presented in Table 11-9. The order that the five plans are presented in Table 11-9 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower emission costs can be seen in the column labeled Rank.

| Table 11-9<br>Summary of CPWC of Base Capacity Expansion Plans<br>Low Emission Costs | | |
|---|---|---|
| Plan | System CPWC ($1,000) | Rank |
| Plan PPA 1 | 18,111,598 | 1 |
| Plan PPA 2 | 18,114,756 | 2 |
| Plan 1 | 18,351,763 | 3 |
| Plan 2 | 18,353,170 | 4 |
| Plan 3 | 18,379,370 | 5 |

## 11.10 $CO_2$ Emission Costs at $10 per Ton

This sensitivity, which is presented for information purposes only, considers the potential economic impact associated with a regulatory environment in which emissions of $CO_2$ would be subject to a cap-and-trade program, similar to that contemplated under the current CAIR and CAMR programs. $CO_2$ is currently not subject to Environmental Protection Agency (EPA) regulation. For this sensitivity, costs were added to each plan based on an estimated cost of $10 per ton of $CO_2$ emitted. The economic dispatch of the plans was not changed to reflect potential changes in operation that might occur due to such an added emission cost. The CPWC for the five base capacity expansion plans are presented in Table 11-10. The order that the five plans are presented in Table 11-10 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower emission costs can be seen in the column labeled Rank.

## 11.11 $CO_2$ Emission Costs at $25 per Ton

This sensitivity, which is presented for information purposes only, considers the potential economic impact associated with a regulatory environment in which emissions of $CO_2$ would be subject to a cap-and-trade program, similar to that contemplated under the current CAIR and CAMR programs. $CO_2$ is currently not subject to EPA regulation. For this sensitivity, costs were added to each plan based on an estimated cost of $25 per ton of $CO_2$ emitted. The economic dispatch of the plans was not changed to reflect potential changes in operation that might occur due to such an added emission cost. The CPWC for the five base capacity expansion plans are presented in Table 11-11. The order that the five plans are presented in Table 11-11 is the same as the order they are presented in Table 10-2, and the impact on the economics of each plan due to the lower emission costs can be seen in the column labeled Rank.

Table 11-10
Summary of CPWC of Base Capacity Expansion Plans
$CO_2$ Emission Costs of $10 per Ton

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 19,969,275 | 1 |
| Plan PPA 2 | 20,067,711 | 2 |
| Plan 1 | 20,230,807 | 4 |
| Plan 2 | 20,285,689 | 5 |
| Plan 3 | 20,169,180 | 3 |

Table 11-11
Summary of CPWC of Base Capacity Expansion Plans
$CO_2$ Emission Costs of $25 per Ton

| Plan | System CPWC ($1,000) | Rank |
|---|---|---|
| Plan PPA 1 | 22,551,328 | 1 |
| Plan PPA 2 | 22,778,943 | 3 |
| Plan 1 | 22,842,434 | 4 |
| Plan 2 | 22,971,347 | 5 |
| Plan 3 | 22,660,427 | 2 |

## 11.12 Summary of Sensitivity Analyses Results

The tornado diagrams shown on Figures 11-1 through 11-5 illustrate the effects of the sensitivities on the CPWC of each of the five plans. Each diagram indicates the magnitude of the CPWC change relative to the base case for each sensitivity case. These diagrams graphically illustrate the projects or issues that contain the most risk or opportunity. Further strategy development can then be focused on these issues. The center line of the tornado diagram represents the CPWC for the base assumptions.

The size of the bars in the tornado diagrams illustrates the magnitude of each variable's effect on the CPWC of a plan. As shown in all diagrams, three of the sensitivities have significant effect on the CPWC of each plan, both of the potential carbon tax sensitivities and the purchase power and natural gas price sensitivity. Variation in the price of $NO_x$ and $SO_2$ emission allowances has the least effect on the CPWC of each plan. Generally, each of the plans presented is equally sensitive to changes in the input parameters. Thus, none of these five plans appears to expose Brazos Electric to any greater risk relative to the other plans based on the analyses performed.

Figures 11-1, 11-2, 11-3, 11-4, and 11-5 illustrate the impact of these sensitivities on each of the plans. As shown, the impact of potential $CO_2$ regulation, high gas prices, and high energy prices has the largest impact on plan cumulative present worth costs.

## 11.13 Risk Mitigation Strategies

As indicated on Figures 11-1 through 11-5, Brazos Electric, similar to other electric utilities, is exposed to the greatest risk from the potential imposition of a carbon tax. The sensitivity with the next largest effect is the price of natural gas and market purchases. Plan 2, the plan with the most coal fired generation, is not as sensitive to changes in the prices of natural gas and market purchases as Plans 1 and 3. Plans PPA 1 and PPA 2 are also less sensitive to natural gas and market purchase prices. This indicates that Brazos Electric may be able to mitigate the impact of changes in natural gas prices by developing and maintaining a diverse mix of natural gas and coal fueled resources. While the implementation of a carbon tax would greatly increase CPWC, the effect would be relatively constant between these plans.

Load growth also has a significant effect on CPWC of these plans. Brazos Electric may wish to encourage its members and customers to investigate demand side management programs that may help reduce the rate of growth Brazos Electric has experienced in the past. As a minimum, Brazos Electric continues to monitor actual load growth compared to forecasts in order to minimize the economic effect of changes (both increases and decreases) from the expected base case load growth.

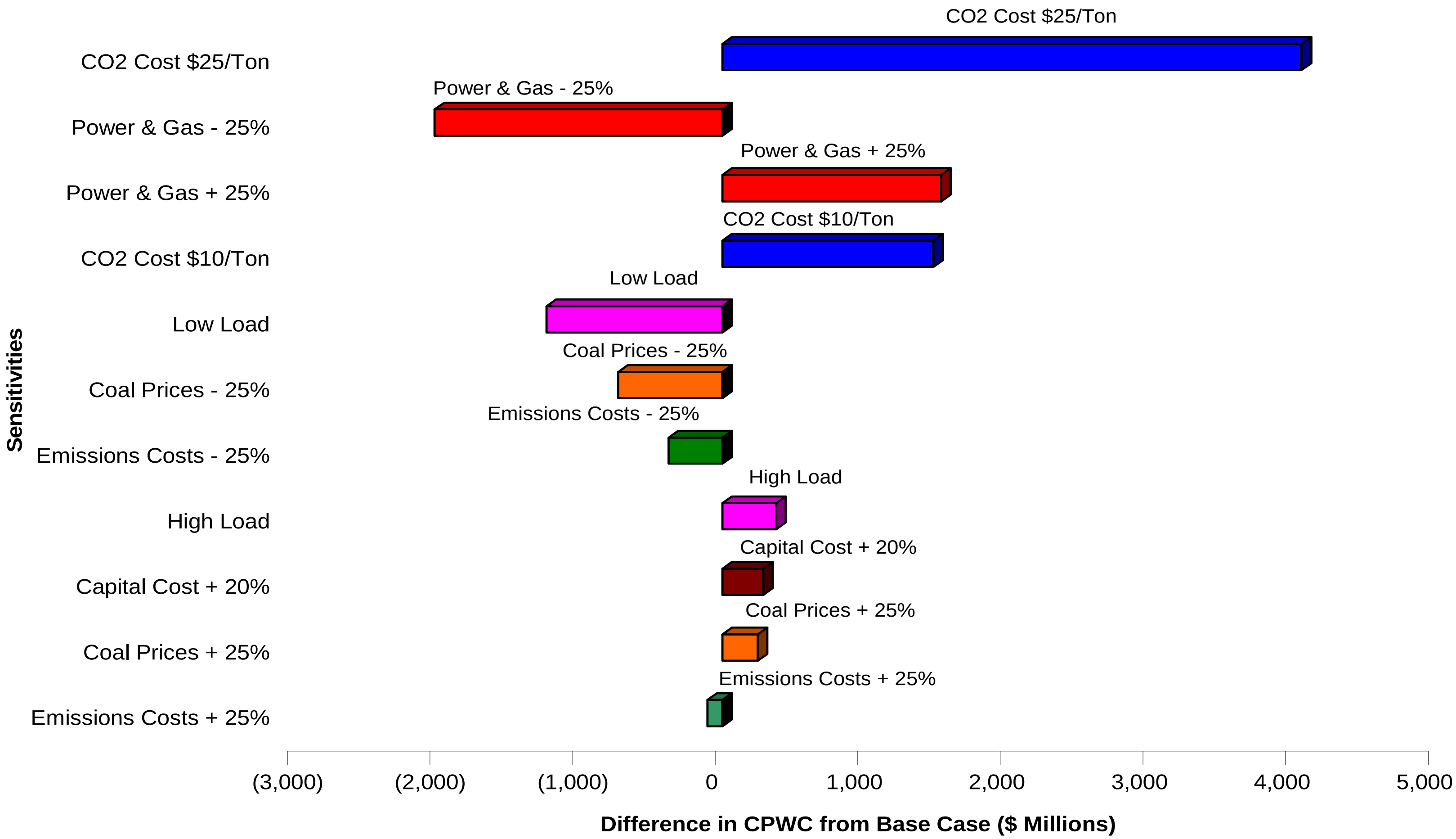


Figure 11-1
Tornado Diagram for Plan PPA-1

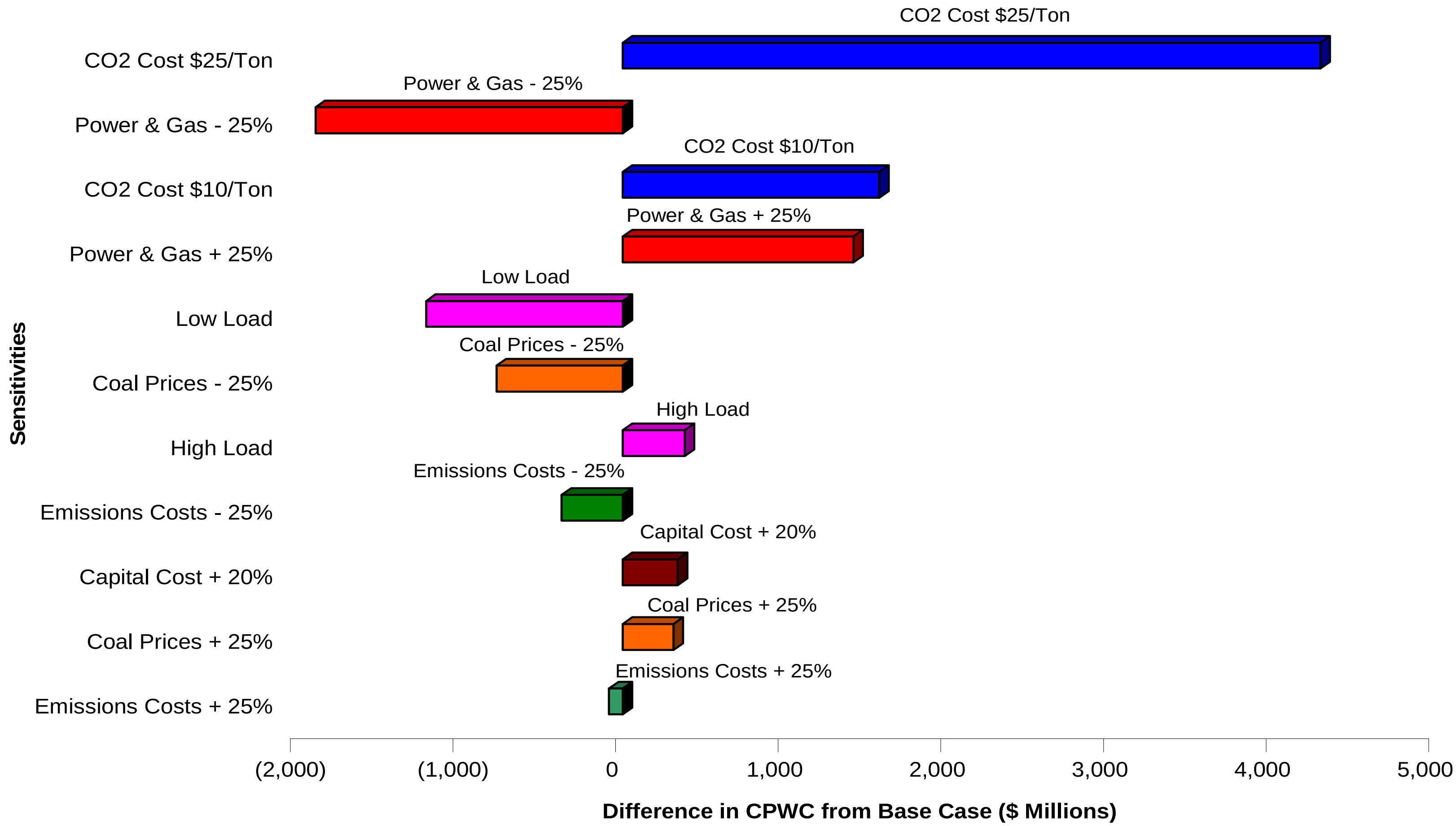


Figure 11-2
Tornado Diagram for Plan PPA-2

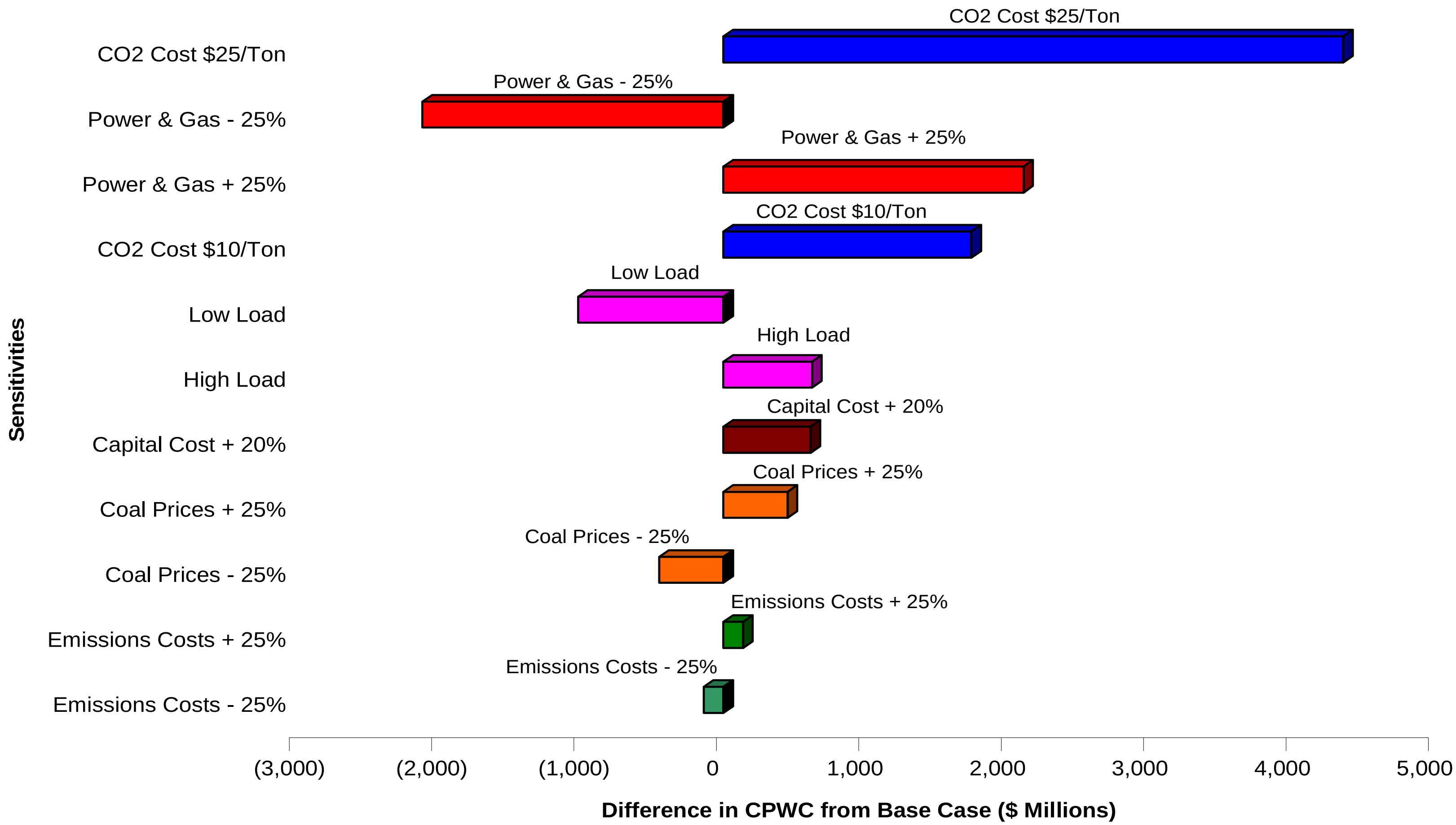


Figure 11-3
Tornado Diagram for Plan 1

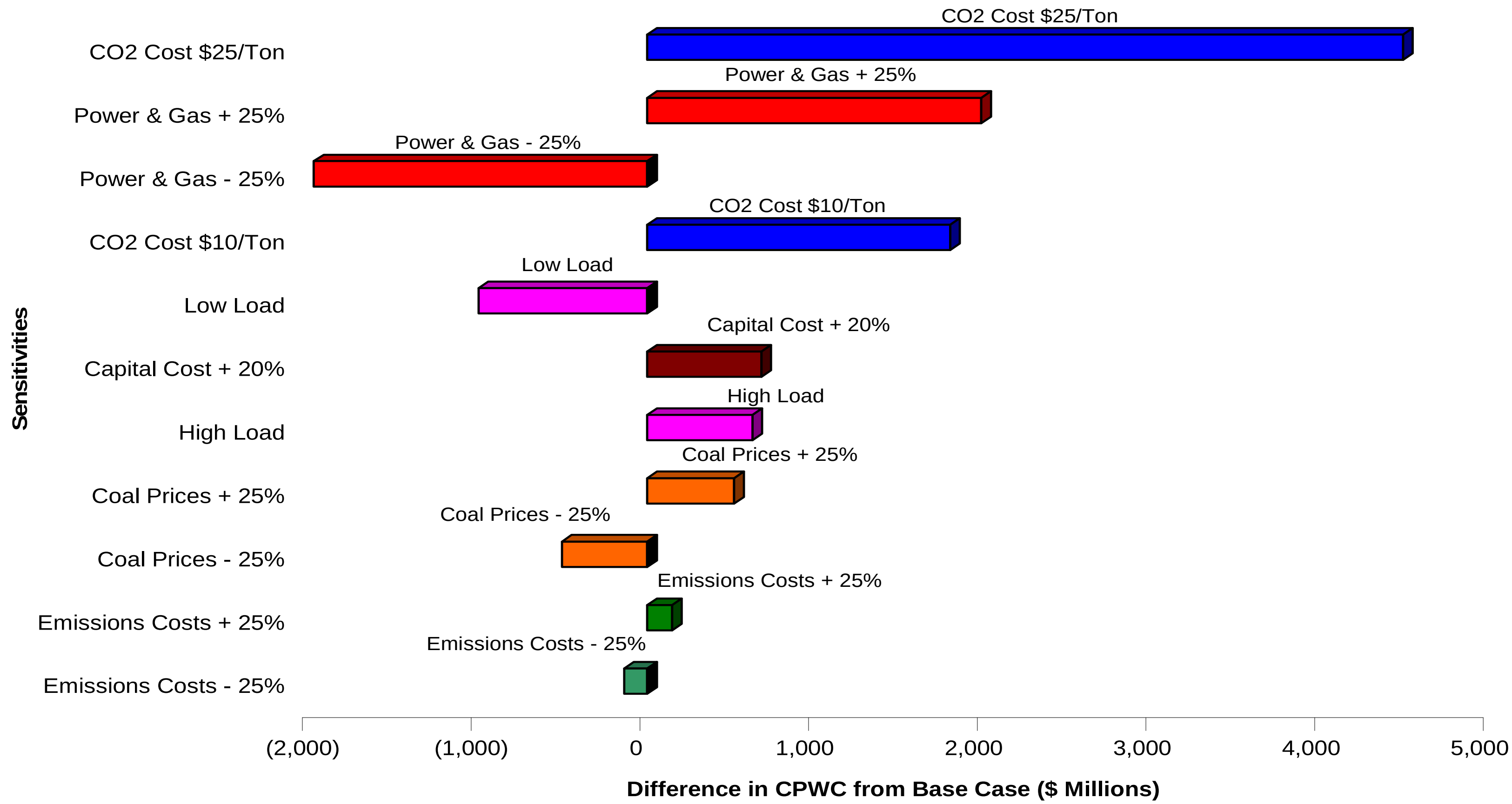


Figure 11-4
Tornado Diagram for Plan 2

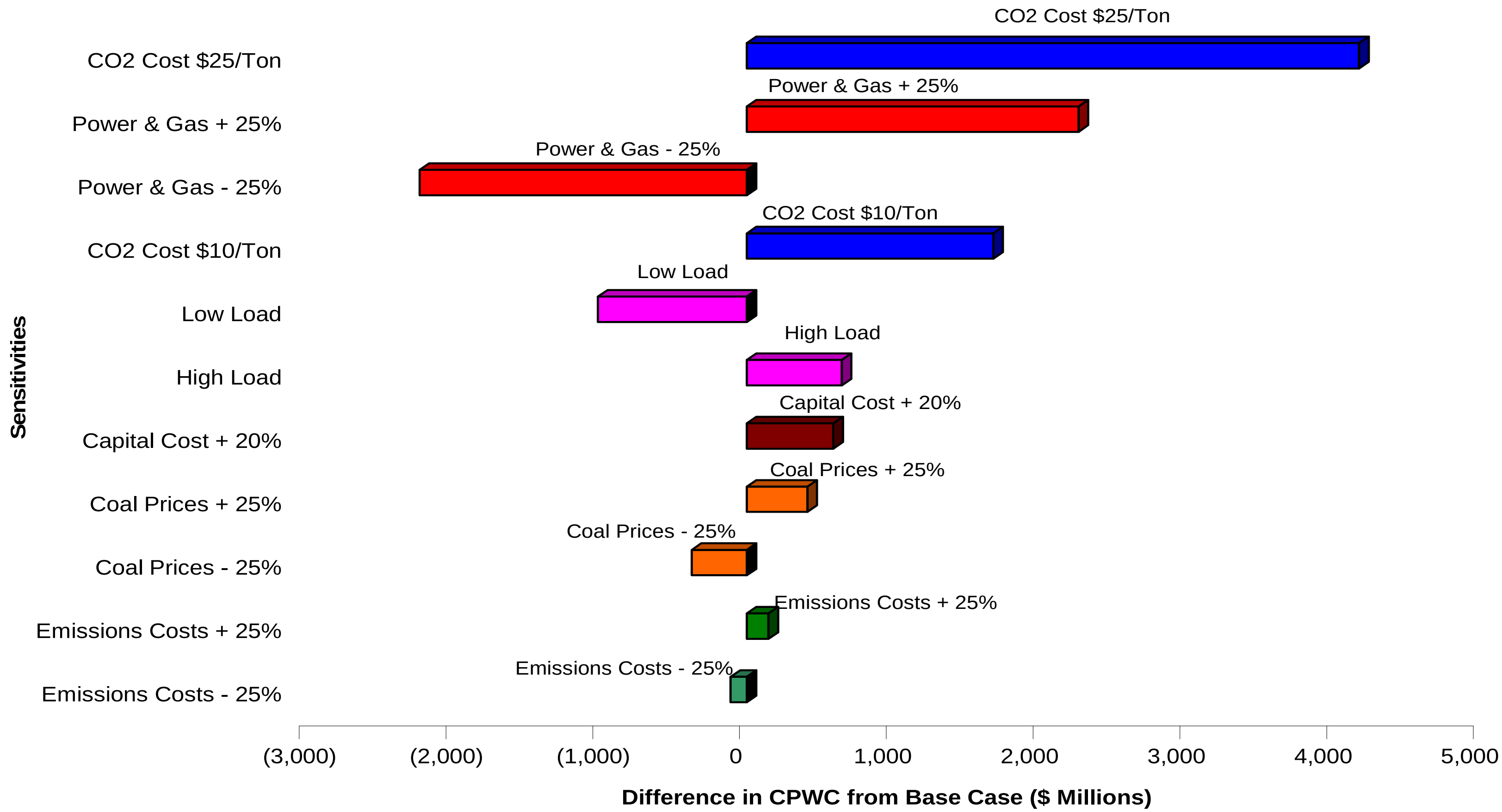


Figure 11-5
Tornado Diagram for Plan 3

# 12.0 Conclusions and Recommendations

Brazos Electric retained Black & Veatch to assist in the preparation of this Power Supply Study to help facilitate its decision-making process regarding selection of future generating unit additions to its system. The Power Supply Study process included the following major tasks completed by Brazos Electric, Black & Veatch, and others:

- Data collection, review, and evaluation.
- Forecasts of fuel prices, forward energy contract and call option prices, load and energy growth, and emission allowance prices.
- Description of Brazos Electric's existing system, including discussion of plans for the Miller and North Texas units.
- Development of performance, capital costs, O&M costs, and emission rate estimates for candidate expansion units.
- Development of a RFP for generating resources available to Brazos Electric.
- Screening analysis of candidate expansion units, including resources offered to Brazos Electric through the RFP.
- Estimation of future capacity addition requirements.
- Economic modeling, including sensitivity and risk analysis.

Conclusions and recommendations developed from the information accumulated and reviewed during the Power Supply Study process are summarized in the following sections.

## 12.1 Conclusions

The Power Supply Study included evaluations of capacity expansion plans over a period from 2006 through 2035. However, the conclusions and recommendations in this study are intended to support capacity expansion plans in the more immediate future. A longer evaluation period was required to ensure that long-term decision-making is not driven by short-term cost savings. It is anticipated that further Power Supply Studies will be required to validate current forecasts and assumptions and reevaluate long-term generation resource commitments. From the evaluations, reviews, forecasts, and modeling conducted for this Power Supply Study, the following conclusions regarding Brazos Electric's electric system were developed:

1. Brazos Electric forecasts continued substantial growth of its demand and energy requirements.

2. Brazos Electric forecasts continued use of short-term purchases of fixed-priced forward energy contracts and call options to meet peak demand.
3. The Power Supply Study was conducted assuming Brazos Electric owns 393 MW of WFEC's Hugo 2 unit going in-service in 2012. It also assumes that North Texas Unit 3 will not be returned to serve during the evaluation period.
4. There are numerous supply-side alternatives that are currently available for potential expansion units, including simple cycle turbines, CC units, coal fired PC units, lignite fired CFB units, and PPAs.
5. Environmental considerations are important for determining the overall total CPWC for a capacity expansion plan. However, changes in the emission allowance costs under CAIR and CAMR do not significantly change the rankings of these plans due to the mix of fuels used in each plan.
6. The implementation of a carbon tax may have a significant effect on future CPWC for all capacity expansion plans.
7. Other than implementation of a carbon tax, the price of natural gas and market purchases have the greatest impact on the CPWC of the capacity expansion plans.
8. Load growth also has a significant effect on the CPWC of these plans.

## 12.2 Recommendations

Evaluation of the base case, sensitivity, and risk analyses conducted on the various capacity expansion plans found that the plans are reasonably close in economic cost. Therefore, it is difficult to identify a single plan as the least-cost alternative under all circumstances. As a result, recommendations from the Power Supply Study include the following:

A. Brazos Electric's needs for capacity and economical energy justify the addition of a combination of baseload, intermediate, and peaking self-build generation resources and long-term PPAs, as well as continued short-term purchases of fixed-priced forward energy contracts and call options.

B. Brazos Electric's needs for capacity and economical energy justify the addition of both coal fired and natural gas fired generating resources in order to maintain a balanced and diverse fuel supply.

C. Brazos Electric should pursue negotiation of long-term baseload PPAs with both LT9 and LT2.

D. Brazos Electric should expeditiously perform a site selection study to identify and secure new greenfield sites suitable for construction of multiple supercritical PC baseload units and multiple gas fired CC units.

E. Brazos Electric should perform detailed analyses and conceptual design studies necessary for environmental permitting of CC unit additions at the existing Jack County and Johnson County brownfield sites. Because these are existing sites, the length of time and cost to bring new units to commercial operation should be less than those for a greenfield development.

F. Brazos Electric should perform conceptual design studies for supercritical PC units and gas fired CC units at potential greenfield sites.

G. Brazos Electric should continue to monitor its load growth annually as changes (both increases and decreases) from the expected load growth may have a significant effect on future capacity expansion plans. As Brazos Electric currently maintains a significant net short position, the greater risk is currently on needing to purchase more capacity and energy from the market at a greater cost rather than a risk of overbuilding.

H. Brazos Electric should continue to monitor regulatory requirements related to air emissions and potential emissions of $CO_2$. Formal regulation of $CO_2$ could have a significant impact on the total CPWC of all plans.

I. Brazos Electric should continue to evaluate renewable resources, especially wind and biomass, and nuclear as these projects are proposed. The RFP was open to renewable energy and nuclear resources, but no proposals were received.

# Update to 2002 Power Plant Site Selection Study

**Prepared For**

## Brazos Electric Power Cooperative

**December 2007**

**Project 47321**

# Update to 2002 Power Plant Site Selection Study

prepared for

## Brazos Electric Power Cooperative
## Waco, Texas

December 2007

Project No. 47321

prepared by

## Burns & McDonnell Engineering Company, Inc.
## Kansas City, Missouri

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## LIST OF ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| 2002 Study | Power Plant Site Selection Study Performed for Brazos in 2002 |
| B&McD | Burns & McDonnell Engineering Company, Inc. |
| Brazos | Brazos Electric Power Cooperative |
| Devon | Devon Energy Services |
| ERCOT | Electric Reliability Council of Texas |
| ETF | Energy Transfer Fuel |
| Falcon | Falcon Gas Storage Company |
| FEMA | Federal Emergency Management Agency |
| FIRM | Flood Insurance Rate Map |
| GPM | Gallons per Minute |
| kV | kilovolt |
| kW | kilowatt |
| MGD | Million Gallons per Day |
| MVA | Megavolt-Ampere |
| MW | Megawatt |
| NGPL | Natural Gas Pipeline Company of America |
| NRHP | National Register of Historic Places |
| NWI | National Wetlands Inventory |
| $O_3$ | Ozone |
| RUS | Rural Utilities Service |
| Supplemental Study | Update to the 2002 Power Plant Site Selection Study |
| T&E | Threatened & Endangered |
| TRWD | Tarrant Regional Water District |
| TWDB | Texas Water Development Board |
| USGS | United States Geological Survey (U.S. Department of the Interior) |
| Walnut Creek SUD | Walnut Creek Special Utility District |

* * * * *

# SECTION 1.0
# INTRODUCTION

# 1.0 INTRODUCTION

In 2002, Burns & McDonnell Engineering Company (B&McD) was retained by Brazos Electric Power Cooperative (Brazos) to perform a power plant site selection study (2002 Study) to identify the most attractive site(s) for the potential development and construction of future generating resources. This report presents an update to the 2002 Study in order to evaluate the existing Jack County and Johnson County generating stations utilizing the same methodology as the 2002 Study (Supplemental Study). The following paragraphs outline the Supplemental Study objectives and methodology.

## 1.1 STUDY OBJECTIVES

Brazos has identified a need for additional intermediate generating resources (annual capacity factors in the range of 40 to 80 percent) in the 2011 to 2014 timeframe. This Supplemental Study was initiated by Brazos in order to investigate the feasibility of incorporating additional gas-fired resources at existing generating stations in order to satisfy these needs.

A target capacity of 500 megawatts (MW) was identified for the proposed intermediate resource addition. This capacity was selected with consideration for the projected amounts of additional intermediate power required by Brazos. The data collected and conclusions reached in this Supplemental Study will be used to assist Brazos in determining the feasibility of installing additional intermediate generation at the Jack County and Johnson County locations as they compare to other previously identified alternatives.

## 1.2 STUDY METHODOLOGY

The principal component of this report is a gas-fired power plant site selection study. The methodologies used to complete this supplemental study are outlined below.

### 1.2.1 Siting Study

The objective of the 2002 Study was to identify the best site or sites for location of future generating resources that may be owned by Brazos. The preferred sites identified in the 2002 Study were those that could accommodate up to 1,000 MW of gas-fired combustion turbine generation and also best meet the following general criteria:

- Satisfy the requirements and guidelines of the Rural Utilities Service (RUS).
- Allow for economical construction of the proposed generating station or stations.

- Minimize adverse environmental and social impacts.
- Possess the necessary physical attributes such as size, topography, and access to adequate fuel and water supplies and transmission facilities.

To verify the suitability of each location to support additional combined cycle generation, the Jack County and Johnson County brownfield locations were evaluated against the same criteria utilized in the 2002 power plant site selection study. These criteria are organized into six categories: Air Quality Impacts, Electrical Transmission, Fuel Supply, Heavy Equipment Delivery, Public Impacts, and Water Supply. The results of this evaluation were compared to the results of the 2002 Study to indicate the relative suitability of each location. A map of the two locations considered in this Supplemental Study is included below as Figure 1-1.

## 1.3 PROJECT TEAM

This Supplemental Study was completed by a multi-disciplinary team of professionals from Brazos and B&McD. The project team included individuals with expertise in the planning, permitting, design and operation of electric generating facilities and individuals with expertise in the planning and design of the electrical transmission system.

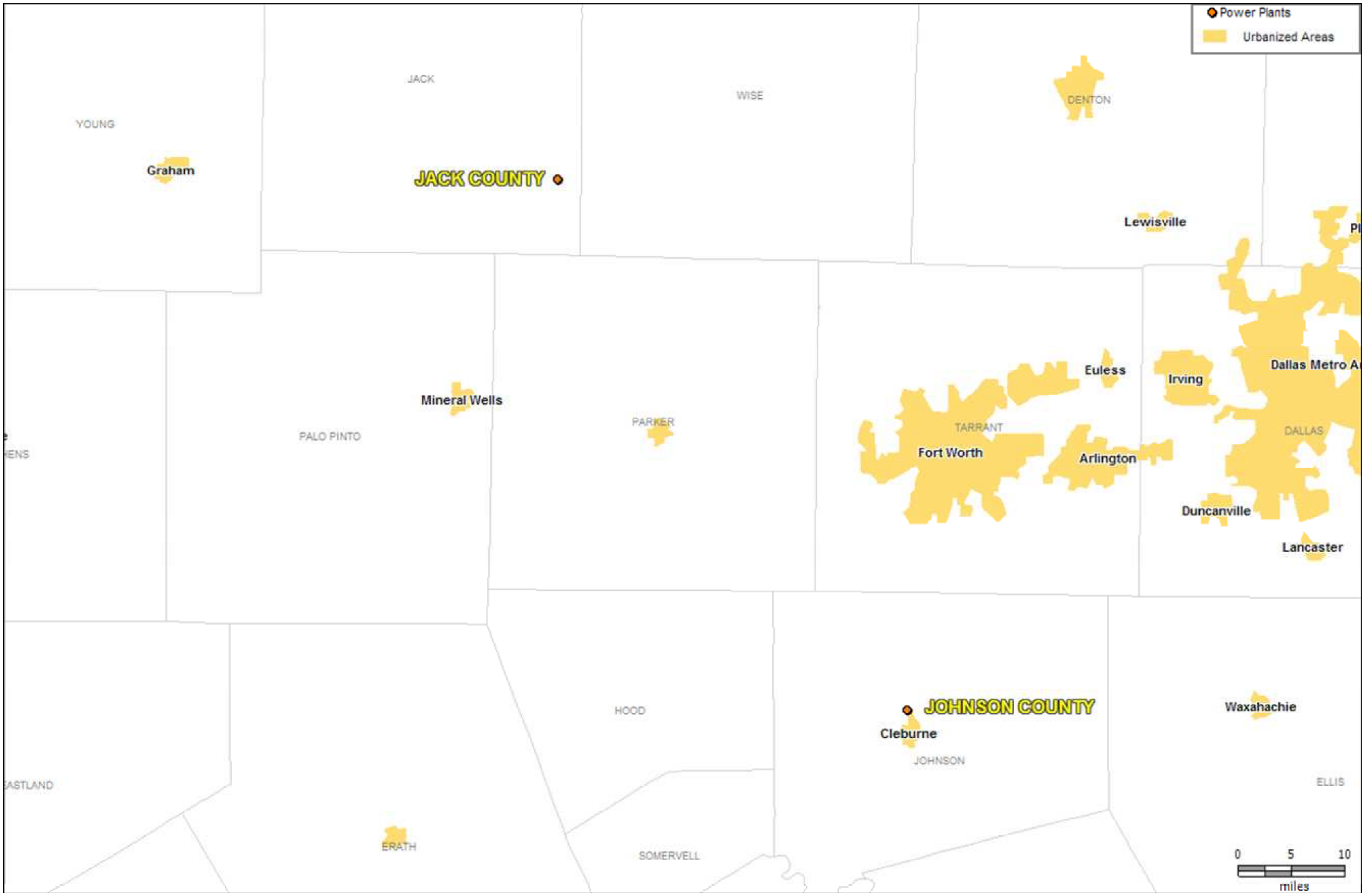
## 1.4 ORGANIZATION OF REPORT

This report is organized into several separate chapters. These individual sections are listed below along with a brief description of their contents.

- Chapter 1.0 – Introduction: A description of the Supplemental Study's objectives, methodology and project team.
- Chapter 2.0 – Jack County Site Description: A description the Jack County site area.
- Chapter 3.0 – Johnson County Site Description: A description the Johnson County site area.
- Chapter 4.0 –Site Evaluation: A discussion of criteria used in the evaluation of site areas and the results of this evaluation.
- Chapter 5.0 – Conclusions: The conclusions reached during the Supplemental Study.

* * * * *

**Figure 1-1: Supplemental Study Locations**




| Brazos Electric Cooperative | **Update to 2002 Power Plant Site Selection Study**<br>Site Locations | Burns & McDonnell SINCE 1898 |
|---|---|---|

# SECTION 2.0

# JACK COUNTY SITE DESCRIPTION

# 2.0 JACK COUNTY SITE DESCRIPTION

This chapter contains a narrative description and maps of the Jack County site area, with an emphasis on characteristics that are important in the subsequent evaluation process. The location shown on the site map is considered to be representative of area available in the general site vicinity but was identified only to aid in the site evaluation process. Based on real estate considerations and further analyses, the site boundaries selected for eventual development could be modified from those shown on the enclosed site map.

## 2.1 JACK COUNTY SITE AREA

The Jack County site area is located in Jack County, Texas, approximately two miles northeast of the town of Joplin. This brownfield site consists of a 2x1 combined cycle facility that is currently in operation and owned by Brazos. A detailed description of the site is provided below. A United States Geological Survey (USGS) topographic map of this site area is included as Figure 2-1 and an aerial image of the area is included as Figure 2-2.

### 2.1.1 Current Site Conditions and Land Use

In addition to the existing power plant, the area surrounding the site includes previously disturbed areas and rangeland. Small wooded areas are also present south and west of the site area. Road access to the site is provided by Farm to Market Road 2210, approximately two miles east of the site. This brownfield site is located at an existing power plant located northeast of Joplin, Texas, or approximately 15 miles southeast of Jacksboro, Texas.

Based on 2000 Census data, Jack County has a population of 8,763 with a density of 9.6 people and 4.0 housing units per square mile of land. The nearest average-sized city is Mineral Wells (pop. 16,946), which is located approximately 25 miles from the site area by road. The nearest large population center is the Fort Worth metropolitan area, located approximately 35 miles from the site area by road.

National Wetlands Inventory (NWI) maps were unavailable for the site; however, based on USGS topographic maps and aerial photographs, no extensive wetlands were identified in the site area adjacent to the existing power plant. The area in the vicinity of the existing power plant consists of rangeland. Small ephemeral stream tributaries to Lake Bridgeport occur in the vicinity of the existing power plant.

Floodplain maps from the Federal Emergency Management Agency (FEMA) were unavailable for Jack County, Texas; however, based on USGS topographic maps and aerial photography, both the existing power plant and surrounding area appear to be outside of the 100-year floodplain.

Due to the predominance of rangeland in the site area, the direct impact to threatened and endangered (T&E) species appears to be limited.

Only one site within Jack County is listed on the National Register of Historic Places (NRHP). The site is located in the vicinity of the City of Jacksboro. Undiscovered subsurface archaeological and cultural resource sites could exist in the vicinity of the existing power plant.

Very few residences occur in the site area. The area in the vicinity of the existing power plant is primarily used for rangeland, indicating that noise and visual impacts appear to be low.

### 2.1.2 Air Quality Impacts

Jack County is classified as an attainment area for all criteria air pollutants. The closest non-attainment area is located in the Dallas-Fort Worth metropolitan area (non-attainment for eight-hour ozone). However, because prevailing winds are typically from the south or southwest, it is unlikely that air emissions from this site area would contribute to air quality problems in the Dallas-Fort worth non-attainment area.

The nearest Class I land area is the Wichita Mountains region, located approximately 119 miles (192 km) northwest of the site. As such, the potential impact to this Class I area's natural, scenic, recreational, or historic qualities is likely negligible.

### 2.1.3 Electrical Transmission

A proposed 499 MW of gas-fired generation has been planned for interconnection at the existing Jack County Plant. An interconnection study has been performed by Brazos in order to assess the system requirements necessary to adequately transmit the additional generation to the Electric Reliability Council of Texas (ERCOT) grid. As part of this study, the following upgrades to the existing network were identified in order to transmit the full output of the 499 MW Jack County Plant addition to the ERCOT grid assuming an interconnection at 345-kV:

- Reconductor or rebuild 44 miles of 345-kV line from Parker to Jacksboro with bundled conductor and single or double circuit construction to result in a rating of at least 1600 MVA

### 2.1.4 Fuel Supply

Natural gas fuel at this location is currently supplied from existing interconnections with Energy Transfer Fuel (ETF), Natural Gas Pipeline Company of America (NGPL) and Devon Energy Services (Devon). In connection with the existing plant, Brazos (i) interconnected with an 8-inch ETF pipeline which crosses the plant site and (ii) constructed a 12-mile, 24-inch pipeline between the plant and interconnections with Devon and NGPL near Bridgeport, Texas.

Additional natural gas fuel could potentially be supplied from ETF or Falcon Gas Storage Company (Falcon). An ETF 16-inch pipeline is located approximately four miles south of the site. Falcon owns and operates a gas storage reservoir located approximately eight miles from the site. Falcon recently completed a 24-inch pipeline connection between the storage reservoir and interconnections with two 36-inch pipelines owned by (i) Atmos Pipeline-Texas and (ii) ETF/Enterprise. Further analysis is required in order to determine if sufficient unallocated transportation and supply of natural gas is available to meet the requirements of additional natural gas-fired generation. However, due to the size of the existing pipelines and the presence of multiple suppliers in the region, the likelihood of additional gas capacity is good.

### 2.1.5 Heavy Equipment Delivery

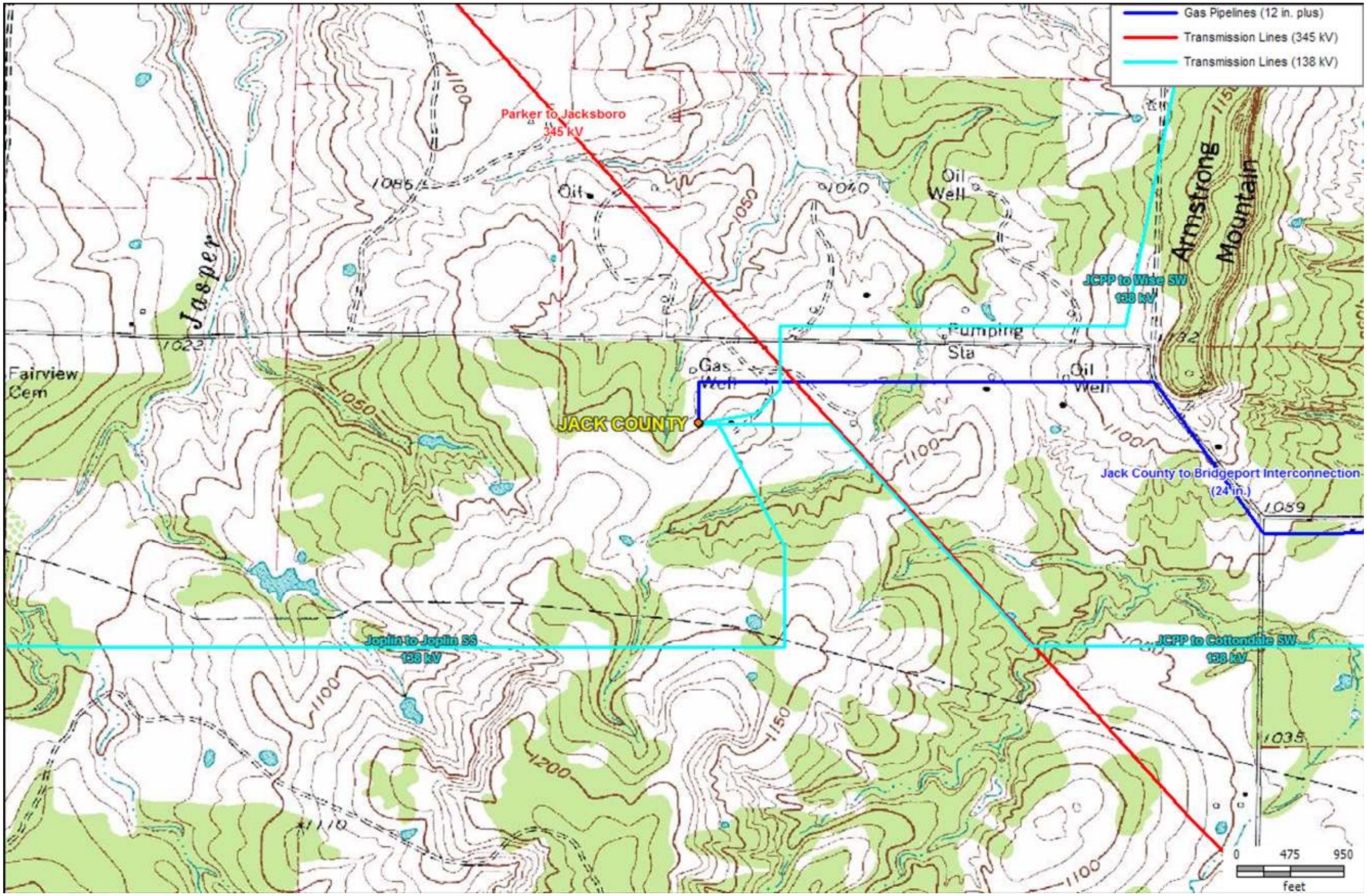
Some of the components of the proposed generating units would be both large and heavy. The most practical way to transport these items to this site area over long distances is by rail. The nearest rail line is a Union Pacific line located approximately 13 miles northeast of the site area and running through the city of Bridgeport and the town of Paradise, Texas.

### 2.1.6 Water Supply

Water for the existing facility is supplied from Lake Bridgeport, located approximately eight miles northeast of the site, pursuant to water supply contracts with Tarrant Regional Water District (TRWD) and Walnut Creek Special Utility District (Walnut Creek SUD). Existing water supply contracts permit a maximum supply of approximately 4,257 acre-feet per year from the TRWD (Lake Bridgeport – part of the TRWD) and 276 acre-feet per year from Walnut Creek SUD. An additional 1,120 acre-feet per year of water supply from the TRWD and an additional 276 acre-feet per year (maximum withdrawal rate of 500,000 gallons per day) from Walnut Creek are available beginning in 2012. As such, a total of approximately 5,929 acre-feet per year, with a maximum withdrawal rate of 11 million gallons per day, will be available to be supplied to this plant. This amount is likely more than sufficient for the amount of generation proposed at this location.

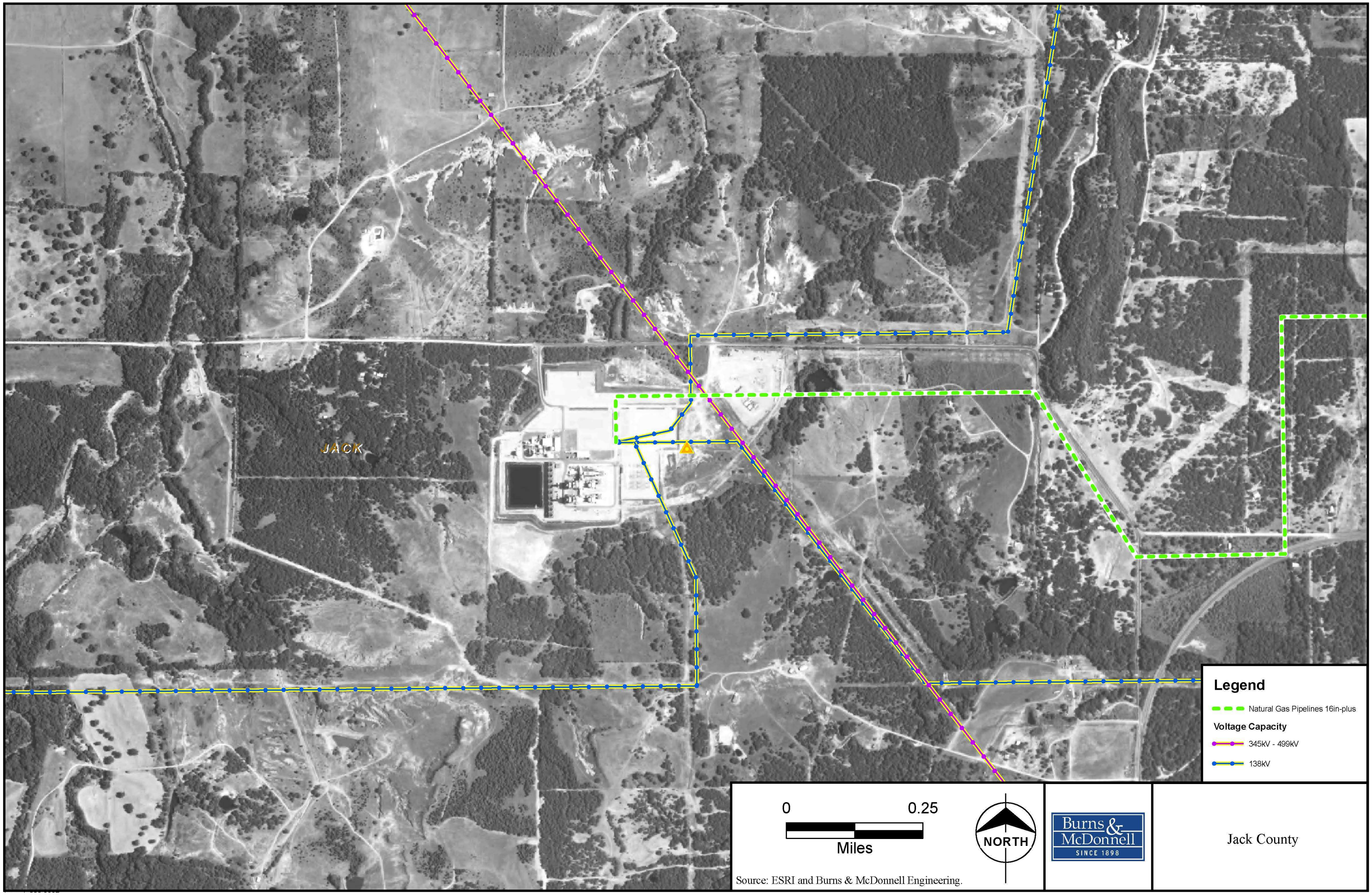
* * * * *

**Figure 2-1: Jack County Siting Area**




| Brazos Electric Cooperative | **Update to 2002 Power Plant Site Selection Study**<br>USGS Topographic Map: Jack County Site Area | Burns & McDonnell SINCE 1898 |
|---|---|---|

**Figure 2-2: Jack County Aerial Image**



# SECTION 3.0

# JOHNSON COUNTY SITE DESCRIPTION

# 3.0 JOHNSON COUNTY SITE DESCRIPTION

This chapter contains a narrative description and map of the Johnson County site area, with an emphasis on characteristics that are important in the subsequent evaluation process. The location shown on the site map is considered to be representative of area available in the general site vicinity but was identified only to aid in the site evaluation process. Based on real estate considerations and further analyses, the site boundaries selected for eventual development could be modified from those shown on the enclosed site map.

## 3.1 JOHNSON COUNTY SITE AREA

The Johnson County site area is located in Johnson County, Texas, and is adjacent to the City of Cleburne. This brownfield site consists of a 1x1 combined cycle cogeneration facility that is currently in operation and owned by Brazos. A detailed description of the site is provided below. A USGS topographic map of this site area is included as Figure 3-1 and an aerial image of the area is included as Figure 3-2.

### 3.1.1 Current Site Conditions and Land Use

In addition to the existing power plant, the area surrounding the site includes previously disturbed areas and rangeland. Road access to the site is provided by State Route 174. This brownfield site is located at an existing power plant on the northwestern edge of Cleburne, Texas.

Based on 2000 Census data, Johnson County has a population of 126,811 with a density of 173.9 people and 63.4 housing units per square mile of land. The nearest average-sized city is Cleburne (pop. 26,005), located approximately two miles from the site area by road. The nearest large population center is the Fort Worth metropolitan area, located approximately 20 miles from the site area by road.

NWI maps were unavailable for the site; however, based on USGS topographic maps and aerial photographs, no extensive wetlands were identified in the site area adjacent to the existing power plant. The area south of the existing power plant consists of previously disturbed grass pasture. Buffalo Creek, which flows north to south, is located west of the existing power plant. A narrow wooded riparian corridor is present along the banks of Buffalo Creek. Fringe wetland habitat may also occur within the wooded riparian corridor along the banks of Buffalo Creek. The 100-year floodplain (no base elevation determined) occurs along Buffalo Creek (FEMA, Johnson County, Texas and Incorporated Areas Panel

125 of 250, Map Number 48251C0125 F, September 27, 1991). The existing power plant is outside of the 100-year flood plain. However, a portion of the grass pasture south of the existing power plant is inundated by a special flood hazard area (Zone A).

Due to the predominance of industrial development and rangeland in the site area, the direct impact to T&E species appears to be limited.

Within Johnson County, five sites are listed on the National Register of Historic Places. Two of the five sites occur in or are within the vicinity of the town of Rio Vista. The remaining three sites are within the City of Cleburne and are not in the vicinity of the existing power plant. Undiscovered subsurface archaeological and cultural resource sites could exist in the vicinity of the existing power plant.

Very few residences occur in the site area. The area in the vicinity of the existing power plant has been developed for industrial facilities or is primarily used for rangeland, indicating that noise and visual impacts appear to be low.

### 3.1.2 Air Quality Impacts

Johnson County is currently classified as non-attainment for eight-hour ozone. This is based upon proximity to the Dallas-Fort Worth metropolitan area located immediately to the north of the site area. Because prevailing winds are from the south, air emissions from this site area could be transported into the Dallas-Forth worth area. In order to permit additional generating units at this site area, Brazos would have to demonstrate, through air dispersion modeling, that additional emissions generated at this site would not contribute significantly to concentrations within the non-attainment area. If these impacts are determined to be significant, these generating units would be subjected to many of the same restrictions, such as the requirement to obtain emissions offsets, that would apply to emissions sources physically located within the non-attainment area.

The nearest Class I land area is the Wichita Mountains region, located approximately 175 miles (282 km) northwest of the site. As such, the potential impact to this Class I area’s natural, scenic, recreational, or historic qualities is likely negligible.

### 3.1.3 Electrical Transmission

A proposed 300 MW of gas-fired generation has been planned for interconnection at the existing Johnson County Plant. An interconnection study has been performed by Brazos in order to assess the system requirements necessary to adequately transmit the additional generation to the ERCOT grid. As part of this study, the following upgrades to the existing network were identified in order to transmit the full output of the 300 MW Johnson County Plant addition to the ERCOT grid assuming an interconnection at 138-kV:

- Loop the existing ONCOR Godley to Air Liquide 138-kV line into the Johnson County Plant
- Rebuild the Johnson County – Air Liquide – Cleburne North – Cleburne Switch line for a rating of at least 650 MVA

### 3.1.4 Fuel Supply

Natural gas fuel at this location is currently supplied by (i) a lateral pipeline to the existing Atmos 36-inch pipeline located two miles northwest of the site and (ii) a lateral pipeline to an existing Energy Transfer Fuel (ETF) 12-inch pipeline located two miles north of the site. Additional natural gas fuel could potentially be supplied by a lateral pipeline to an existing 36-inch pipeline located eight miles south of the site which is jointly owned by ETF and Enterprise. Further analysis is required in order to determine if sufficient unallocated supply of natural gas is available to meet the requirements of adding additional natural gas-fired generation. However, due to the size of the existing pipelines and the presence of multiple suppliers in the region, the likelihood of additional gas capacity is good.

### 3.1.5 Heavy Equipment Delivery

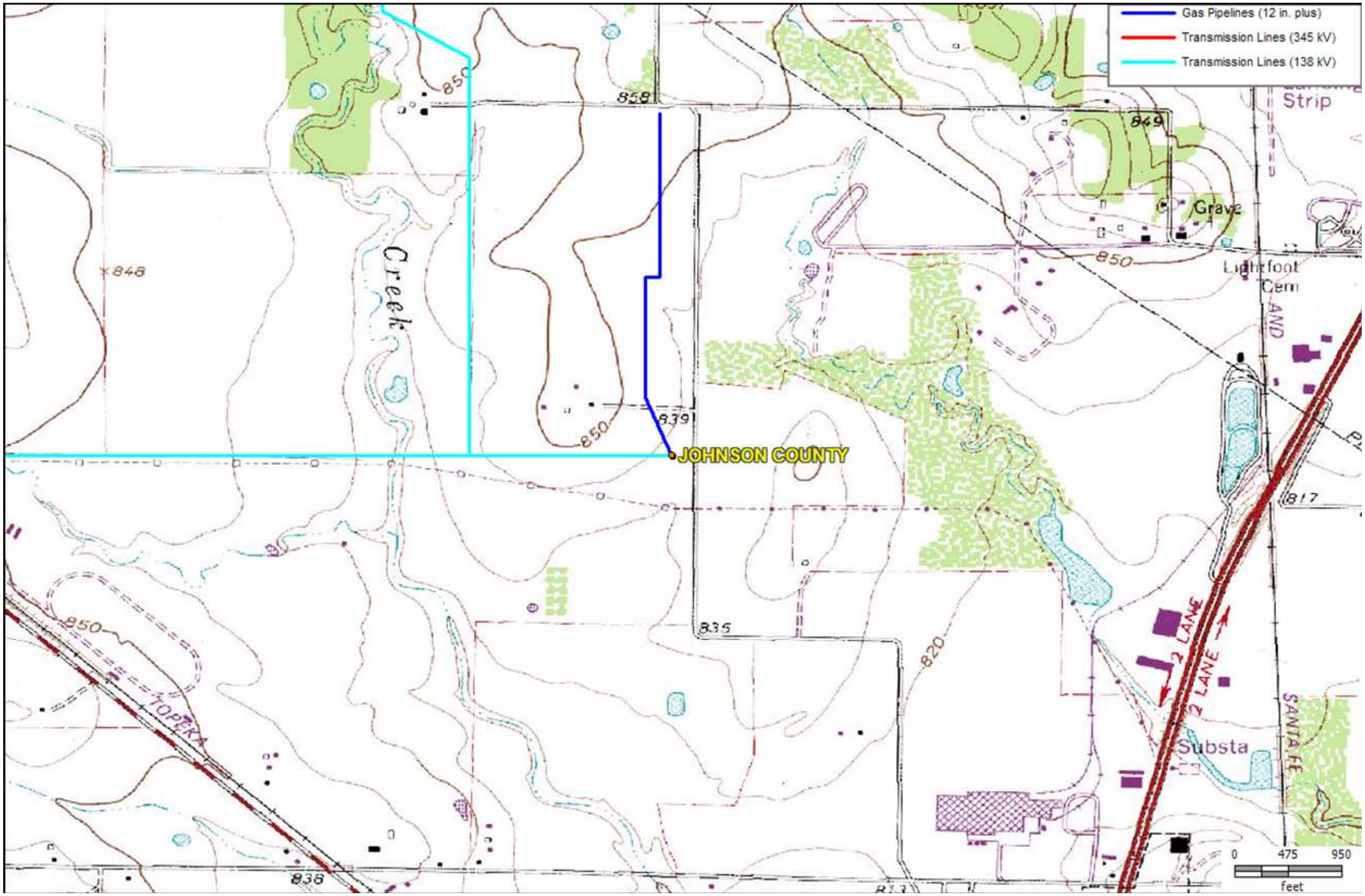
Some of the components of the proposed generating units would be both large and heavy. The most practical way to transport these items to this site area over long distances is by rail. The nearest rail line is an industrial rail spur located adjacent to the existing plant to the east. This spur connects to a Burlington Northern Santa Fe line located approximately one mile east of the site area and running through the city of Cleburne, Texas.

### 3.1.6 Water Supply

Water for the existing facility is supplied in the form of grey water from the City of Cleburne. A maximum of 1.7 million gallons per day (MGD) of grey water is currently being used. The city of Cleburne has the capacity to provide a total of 3.4 MGD to Brazos. As such, it appears that this is a continued viable option for supplying water should additional generation be added at this site.

* * * * *

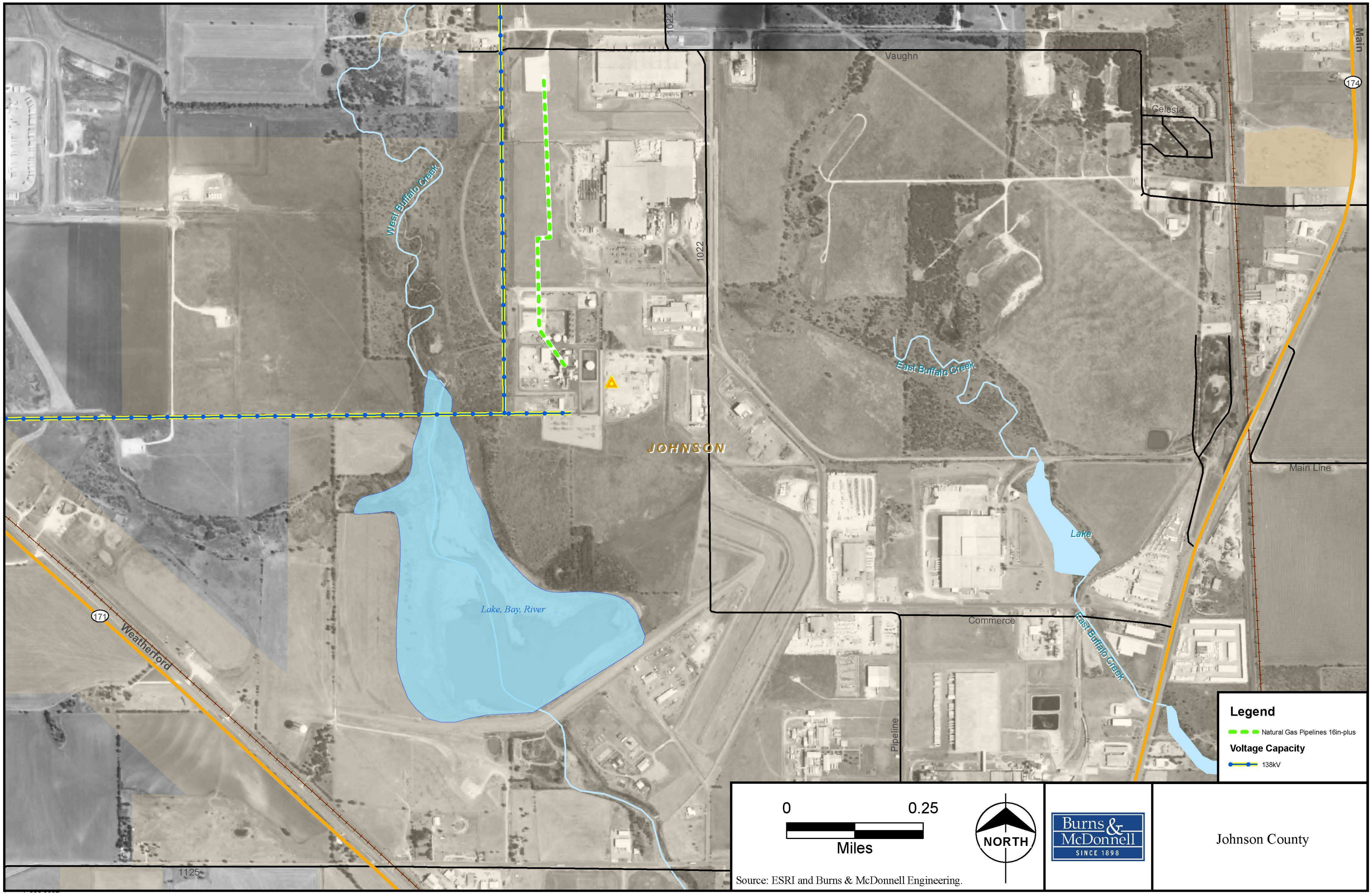
**Figure 3-1: Johnson County Siting Area**




Update to 2002 Power Plant Site Selection Study

USGS Topographic Map: Johnson County Site Area

## Figure 3-2: Johnson County Aerial Image



# SECTION 4.0

# SITE EVALUATION

# 4.0 SITE EVALUATION

A numerical decision analysis process was used to rank the site areas. The first step in using such a process is to identify the objectives or criteria to be used to evaluate the alternatives. The process used to select the site areas was based on consideration of each of the major characteristics required for an acceptable site such as fuel supply, water availability, and electric transmission. Therefore, the site areas that have the necessary infrastructure are assumed to meet minimum site requirements. The focus of the site evaluation, and the criteria discussed in this section, was to assess the relative advantages and disadvantages of each power plant site area.

The evaluation criteria used to judge the relative suitability of the site areas to support a gas-fired generation facility cover a number of specific attributes. Each of these attributes represents a characteristic that is important in the evaluation of prospective sites and also serves to differentiate the site areas from one another. These evaluation criteria are not equivalent in their importance to the decision-making process. Therefore, each criterion was also assigned a weight indicative of its relative importance to the decision process. Criteria with the highest weights are considered the most critical for site development. The assignment of weights to the evaluation criteria was a subjective process based on the collective professional judgment of Brazos and the Burns & McDonnell staff who participated in this Study.

In total, six different criteria were used to evaluate the candidate site areas. These criteria were organized into categories and allocated relative weights adding up to an overall weighted total of 41. For example, the Electrical Transmission category was assigned a weight of 10. Therefore, nearly 25 percent of the overall evaluation scores were based on electrical transmission impacts. A detailed discussion of each of these criteria, which includes the rationale used to assign the rating for each criterion and the resulting score for each of the site areas, is included in the following paragraphs.

## 4.1 AIR QUALITY IMPACTS

Ideally, the proposed generating facilities should be located on a site where air quality conditions are favorable. Favorable air quality conditions at a given potential site area are those where an air construction permit and operation permit for the planned generating units can be obtained in a timely manner without significant permit conditions or other restrictions. The relative attractiveness of the potential site areas with regard to air quality are generally based on the assessment of air quality attainment status and potential impacts the proposed facility may have on nearby Class I areas.

In the 2002 study, all of the potential gas plant site areas were located in attainment areas for all air criteria pollutants and no Class I areas were affected by the proposed facility. Therefore, no significant obstacles were identified in obtaining an air emissions permit at any of the gas plant potential site areas. The only area of concern was at the Maypearl site area where prevailing winds may transport emissions from this site into the Dallas-Fort Worth non-attainment area. However, evaluating this potential impact could only be accomplished by air dispersion modeling. Therefore, for the 2002 study, the Maypearl site was assigned a score of eight and all other potential gas plant site areas were assigned scores of ten. Since air quality impacts were not considered a significant concern, this criterion was assigned a weight of only four.

In the Supplemental Study, neither the Jack County nor the Johnson County site areas are close enough in proximity to Class I areas to cause significant concern with adding additional generation at either site. Further, although Jack County is in attainment for all criteria pollutants, portions of Johnson County, based on its proximity to the Dallas-Fort Worth metropolitan area, are in non-attainment for eight-hour ozone. Therefore, the Johnson County site was assigned a score of eight and the Jack County site was assigned a score of ten for the air quality impacts criterion.

Results of the air quality impacts assessment from both the 2002 Study and the Supplemental Study are included in Table 4-1.

**Table 4-1: Air Quality Impacts Evaluation Scores**

| Site Name | Evaluation Score |
|---|---|
| Alvord | 10 |
| Boonsville | 10 |
| Bridgeport | 10 |
| Flatrock | 10 |
| Huckabay | 10 |
| Huckabay Gas Yard | 10 |
| Maypearl | 8 |
| Montague | 10 |
| Santo | 10 |
| Stephenville | 10 |
| Vineyard | 10 |
| Whitewright | 10 |
| Wizard Wells | 10 |
| Jack County | 10 |
| Johnson County | 8 |

## 4.2 ELECTRICAL TRANSMISSION

Each potential site area must have a feasible means to connect the proposed generating units into the regional transmission network in order to deliver this power to Brazos' customers. The transmission construction necessary to accomplish this was estimated by Brazos from preliminary transmission analyses for each potential site area. For this Supplemental Study, Brazos has submitted formal generation interconnection requests for both Johnson County and Jack County to the Electric Reliability Council of Texas (ERCOT). These requests will initiate more detailed transmission analyses that will verify or revise these preliminary transmission construction estimates.

Providing transmission service to the proposed power plant is the responsibility of ERCOT and not Brazos Electric. Therefore, the costs associated with any required transmission improvements for this project would not be born directly by Brazos but by all of the electric customers in Texas. Even so, the amount of transmission construction required at each potential site area is a significant evaluation factor as it will impact the permitting and approval process for this project. The scores for this criterion were assigned based on the weighted length of required transmission construction, using the criteria listed in Table 4-2. The weights used to calculate the weighted length of transmission construction are listed below.

- Single circuit 138-kV reconstruction or reconductoring: Weight = 0.5
- Single circuit 345-kV reconstruction or reconductoring: Weight = 0.75
- Double circuit 345-kV reconstruction or reconductoring: Weight = 1.0
- New 138-kV line construction: Weight = 1.0

- New 345-kV line construction: Weight = 1.5

**Table 4-2: Electrical Transmission Rating Criteria**

| Weighted Line Construction (C) (miles) | Evaluation Score |
|---|---|
| C ≤ 10 | 10 |
| 10 < C ≤ 20 | 9 |
| 20 < C ≤ 30 | 8 |
| 30 < C ≤ 40 | 7 |
| 40 < C ≤ 50 | 6 |
| 50 < C ≤ 60 | 5 |
| 60 < C ≤ 70 | 4 |
| 70 < C ≤ 80 | 3 |
| 80 < C ≤ 90 | 2 |
| 90 < C ≤ 100 | 1 |

Results of the electrical transmission assessment from both the 2002 Study and the Supplemental Study are included in Table 4-3 along with the amount of weighted transmission line construction required for each site. The Electrical Transmission criterion was assigned a weight of ten.

**Table 4-3: Electrical Transmission Evaluation Scores**

| Site Name | Weighted Line Construction (miles) | Evaluation Score |
|---|---|---|
| Alvord | 75 | 3 |
| Boonsville | 30 | 8 |
| Bridgeport | 75 | 3 |
| Flatrock | 48.25 | 0 |
| Huckabay | 172.5 | 0 |
| Huckabay Gas Yard | 172.5 | 0 |
| Maypearl | 15 | 9 |
| Montague | 127.5 | 0 |
| Santo | 172.5 | 0 |
| Stephenville | 172.5 | 0 |
| Vineyard | 30 | 8 |
| Whitewright | 59.25 | 5 |
| Wizard Wells | 60 | 5 |
| Jack County | 44 | 6 |
| Johnson County | 11 | 9 |

## 4.3 FUEL SUPPLY

Each suitable site must have access to a reliable supply of natural gas. This requires that the site be located where it can be served by a large capacity natural gas pipeline. The ratings for this criterion were assigned based on the total diameter of the pipelines crossing the site area. At site areas where more than one natural gas pipeline was located and the total diameter added together was greater than 36 inches, a criterion score of ten was given. Another single point was added to the initial score if the second pipeline was owned by a separate supplier. At sites where the natural gas pipeline was owned by Atmos Pipeline-Texas ("Atmos", formerly TXU Lone Star Pipeline), a single point was subtracted from the initial score because Atmos had stated it could not provide firm natural gas delivery. The scores for this criterion were assigned using the criteria listed in Table 4-4.

**Table 4-4: Fuel Supply Rating Criteria**

| Gas Pipeline Diameter (D) (inches) | Evaluation Score |
|---|---|
| D ≥ 36 | 10 |
| 32 < D < 36 | 9 |
| 28 < D ≤ 32 | 8 |
| 24 < D ≤ 28 | 7 |
| 20 < D ≤ 24 | 6 |
| 16 < D ≤ 20 | 5 |
| 12 < D ≤ 16 | 4 |
| 8 < D ≤ 12 | 3 |
| 4 < D ≤ 8 | 2 |
| D ≤ 4 | 1 |

In general in the 2002 study, all of the potential gas transporters indicated that securing a reliable gas supply would not be a significant problem for Brazos. In cases where pipeline improvements would be necessary, all transporters were generally willing to make those improvements as long as Brazos Electric was willing to commit to a long-term supply contract that will allow them recoup these investments.

In the Supplemental Study, both the Jack County and Johnson County sites are served by multiple large diameter natural gas pipelines owned by multiple entities. As such, both sites were given a score of eleven and are likely to possess the fuel infrastructure necessary for adding additional gas-fired generation.

Results of the fuel supply assessment from both the 2002 Study and the Supplemental Study are included in Table 4-5. The Fuel Supply criterion was assigned a weight of ten.

**Table 4-5: Fuel Supply Evaluation Scores**

| Site Name | Evaluation Score |
|---|---|
| Alvord | 5 |
| Boonsville | 11 |
| Bridgeport | 11 |
| Flatrock | 9 |
| Huckabay | 9 |
| Huckabay Gas Yard | 10 |
| Maypearl | 11 |
| Montague | 5 |
| Santo | 4 |
| Stephenville | 4 |
| Vineyard | 4 |
| Whitewright | 5 |
| Wizard Wells | 4 |
| Jack County | 11 |
| Johnson County | 11 |

## 4.4 HEAVY EQUIPMENT DELIVERY

Modern construction techniques and economics favor delivery of combustion turbine components and related equipment in large prefabricated modules. Transport of these large and/or heavy components to a site is practical over long distances only by rail or barge. Since there are no navigable rivers in the study area that can accommodate barge traffic, the ideal site for this criterion was one that was located adjacent to an existing rail spur.

When immediate access to a rail line is unavailable, it is possible to transport these heavy loads by truck using special trailers, although shorter distances are preferred. An additional concern with this method of transportation is the presence of obstacles such as bridges or other structures with load limitations. The ratings for this criterion were assigned based on the haul distance, along the most likely route, from the site to an existing rail siding based on the criteria listed in Table 4-6.

**Table 4-6: Heavy Equipment Delivery Rating Criteria**

| Distance to Rail (D) (miles) | Evaluation Score |
|---|---|
| $D \leq 2$ | 10 |
| $2 < D \leq 4$ | 9 |
| $4 < D \leq 6$ | 8 |
| $6 < D \leq 8$ | 7 |
| $8 < D \leq 10$ | 6 |
| $10 < D \leq 12$ | 5 |
| $12 < D \leq 14$ | 4 |
| $14 < D \leq 16$ | 3 |
| $16 < D \leq 18$ | 2 |
| $18 < D \leq 20$ | 1 |

Results of the heavy equipment delivery assessment from both the 2002 Study and the Supplemental Study are included in Table 4-7 along with the estimated haul distance from the nearest railroad to each site. The Heavy Equipment Delivery criterion was assigned a weight of two.

**Table 4-7: Heavy Equipment Delivery Evaluation Scores**

| Site Name | Distance to Rail (miles) | Evaluation Score |
|---|---|---|
| Alvord | 3 | 9 |
| Boonsville | 14 | 4 |
| Bridgeport | 0.5 | 10 |
| Flatrock | 10 | 4 |
| Huckabay | 13 | 4 |
| Huckabay Gas Yard | 14 | 4 |
| Maypearl | 7.5 | 7 |
| Montague | 14 | 4 |
| Santo | 0 | 10 |
| Stephenville | 5 | 8 |
| Vineyard | 17.5 | 2 |
| Whitewright | 2 | 10 |
| Wizard Wells | 10 | 6 |
| Jack County | 13.5 | 4 |
| Johnson County | 0.5 | 10 |

## 4.5 PUBLIC IMPACTS

The site areas were evaluated to assess the relative impacts to the public that could result from construction and operation of the proposed generating facilities at each site area. The primary sources of public impacts are dislocation of residents and potential noise and visual impacts to nearby residents and passing motorists. Since it is unlikely that residents will be displaced at any of the site areas, the initial ratings for this criterion were assigned based on the distance from the site area to the nearest town or city, as listed in Table 4-8.

**Table 4-8: Public Impacts Rating Criteria**

| Distance (D) to Nearest Town (miles) | Evaluation Score |
|---|---|
| $D > 10$ | 10 |
| $9 < D \leq 10$ | 9 |
| $8 < D \leq 9$ | 8 |
| $7 < D \leq 8$ | 7 |
| $6 < D \leq 7$ | 6 |
| $5 < D \leq 6$ | 5 |
| $4 < D \leq 5$ | 4 |
| $3 < D \leq 4$ | 3 |
| $2 < D \leq 3$ | 2 |
| $1 < D \leq 2$ | 1 |

Results of the public impacts assessment from both the 2002 Study and the Supplemental Study are included in Table 4-9 along with distances from each site to the nearest town. The Public Impacts criterion was assigned a weight of five.

**Table 4-9: Public Impacts Evaluation Scores**

| Site Name | Distance to Town (miles) | Evaluation Score |
|---|---|---|
| Alvord | 9 | 8 |
| Boonsville | 11 | 10 |
| Bridgeport | 3 | 2 |
| Flatrock | 5 | 9 |
| Huckabay | 10 | 9 |
| Huckabay Gas Yard | 10 | 9 |
| Maypearl | 14 | 10 |
| Montague | 12 | 10 |
| Santo | 14 | 10 |
| Stephenville | 5 | 4 |
| Vineyard | 14 | 10 |
| Whitewright | 10 | 9 |
| Wizard Wells | 10.5 | 10 |
| Jack County | 8 | 7 |
| Johnson County | 3.5 | 3 |

## 4.6 WATER SUPPLY

The water requirements of the generating units at a given site will vary depending on a number of factors including the number, size, and type of the generating units.

The availability of water resources varies across the Study area and is a very important evaluation factor. Electric generating units must have high availability. Therefore, when these generating units depend on a supply of water to operate, this water supply must also have a high availability. Previous research during the 2002 Study into potential water supplies revealed that the Study area was underlain by productive groundwater aquifers. However, these aquifers were stressed in many areas by existing withdrawals. Thus, the potential for developing a surface water resource was considered higher based on reduced competition. Both the Brazos River Authority and the Red River Authority indicated during the 2002 Study that they had water available for sale. As such, the initial ratings for this criterion were assigned based on distance to one of these two surface water sources. These ratings were assigned using the criteria listed below in Table 4-10.

**Table 4-10: Water Supply Rating Criteria**

| Distance (D) to Brazos or Red River (miles) | Evaluation Score |
|---|---|
| D ≤ 5 | 10 |
| 5 < D ≤ 10 | 9 |
| 10 < D ≤ 15 | 8 |
| 15 < D ≤ 20 | 7 |
| 20 < D ≤ 25 | 6 |
| 25 < D ≤ 30 | 5 |
| 30 < D ≤ 35 | 4 |
| 35 < D ≤ 40 | 3 |
| 40 < D ≤ 45 | 2 |
| 45 < D ≤ 50 | 1 |

Additionally, based on information provided for each county by the Texas Water Development Board (TWDB), an additional four points (limited to a maximum of score of ten) were added to a site's score if it was in an area with a reasonable prospect of developing a groundwater source. Results of the water supply assessment from both the 2002 Study and the Supplemental Study are included in Table 4-11 along with distances from each site to the aforementioned rivers and groundwater availability estimates. The Water Supply criterion was assigned a weight of ten.

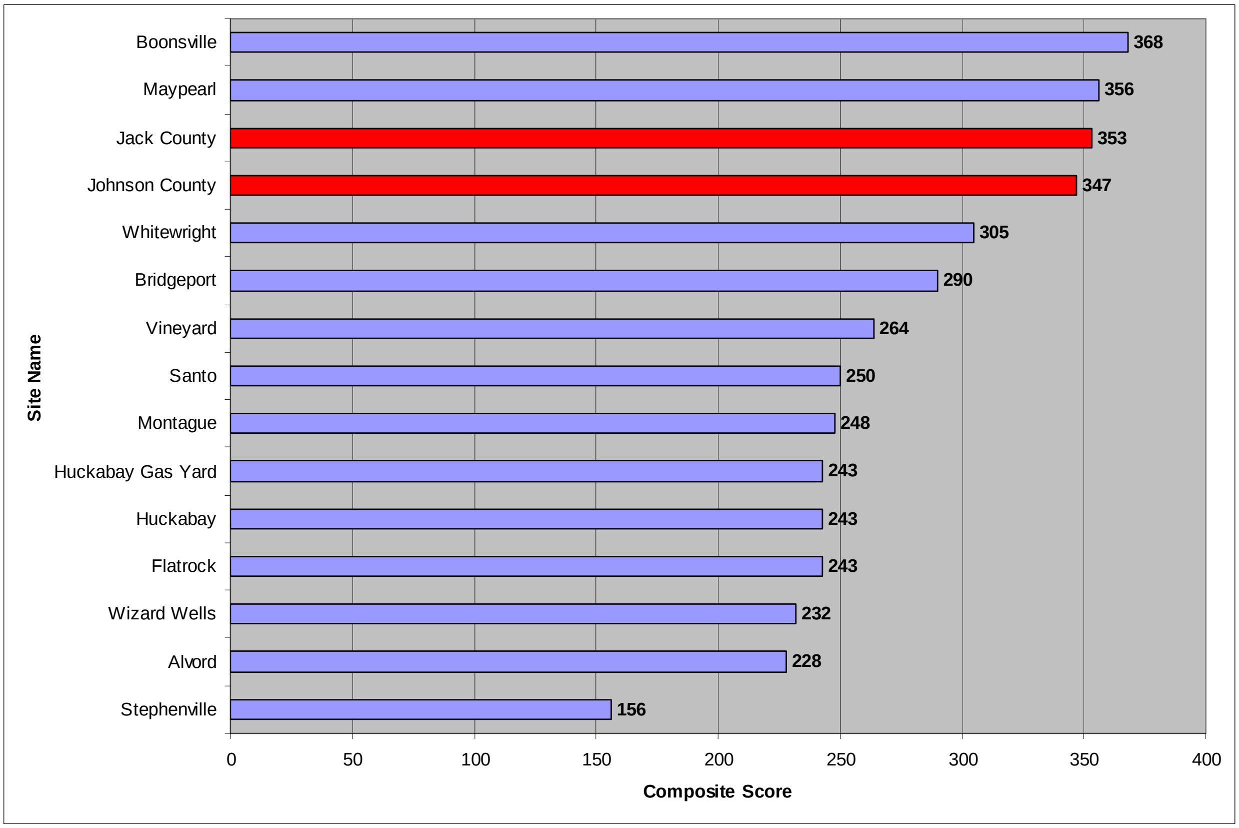
**Table 4-11: Water Supply Evaluation Scores**

| Site Name | Distance to Brazos/Red River (miles) | Groundwater | Evaluation Score |
|---|---|---|---|
| Alvord | 47 | Some | 5 |
| Boonsville | 32 | Some | 8 |
| Bridgeport | 41 | Some | 8 |
| Flatrock | 44 | Little | 6 |
| Huckabay | 25 | Patchy | 6 |
| Huckabay Gas Yard | 25.5 | Patchy | 5 |
| Maypearl | 24.5 | Little | 6 |
| Montague | 20 | Some | 10 |
| Santo | 2 | Some | 10 |
| Stephenville | 32.5 | Patchy | 4 |
| Vineyard | 26 | Little | 5 |
| Whitewright | 20 | Some | 10 |
| Wizard Wells | 31 | Little | 4 |
| Jack County | 22 | Some | 10 |
| Johnson County | 13 | Little | 8 |

## 4.7 EVALUATION SUMMARY

The individual scores for each candidate site and criterion were used along with the corresponding weights to calculate a weighted composite score for each site. These composite scores are calculated as the sum of the products of each individual score and criterion weight. Table 4-12 is a summary of the site scoring from the 2002 Study. Table 4-13 is a summary of the Jack County and Johnson County evaluation scores for adding additional generation at each site based on the 2002 Study criteria. Finally, Figure 4-1 below is a graphical presentation of the weighted composite scores.

**Figure 4-1: Composite Site Evaluation Scores**




In the 2002 Study, the five top-ranked sites were the Boonsville, Bridgeport, Maypearl, Whitewright and Vineyard site areas. When introducing the Jack County and Johnson County site areas as part of the Supplemental Study, these two sites became the third and fourth highest ranked sites, respectively.

The evaluation process presented in this chapter is intended only as a screening tool. Additional analyses, including consideration of strategic issues, should be completed in order to further differentiate between the two sites considered in this Supplemental Study. Although Jack County is ranked slightly higher than Johnson County, both sites appear suitable for installing additional generation.

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## Table 4-12: Site Area Evaluation Summary – 2002 Study

| | | Potential 1,000 MW Gas Plant Site Areas | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Criteria/Subcriteria** | **Weight** | **Alvord** | **Boonsville** | **Bridgeport** | **Flatrock** | **Huckabay** | **Huckabay Gas Yard** | **Maypearl** | **Montague** | **Santo** | **Stephenville** | **Vineyard** | **Whitewright** | **Wizard Wells** |
| Air Quality Impacts | 4 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 10 | 10 | 10 | 10 | 10 | 10 |
| Electrical Transmission | 10 | 3 | 8 | 3 | 0 | 0 | 0 | 9 | 0 | 0 | 0 | 8 | 5 | 5 |
| Fuel Supply | 10 | 5 | 11 | 11 | 9 | 9 | 10 | 11 | 5 | 4 | 4 | 4 | 5 | 4 |
| Heavy Equipment Delivery | 2 | 9 | 4 | 10 | 4 | 4 | 4 | 7 | 4 | 10 | 8 | 2 | 10 | 6 |
| Public Impacts | 5 | 8 | 10 | 2 | 9 | 9 | 9 | 10 | 10 | 10 | 4 | 10 | 9 | 10 |
| Water Supply | 10 | 5 | 8 | 8 | 6 | 6 | 5 | 6 | 10 | 10 | 4 | 5 | 10 | 4 |
| **Weighted Totals** | **41** | **228** | **368** | **290** | **243** | **243** | **243** | **356** | **248** | **250** | **156** | **264** | **305** | **232** |

## Table 4-13: Site Area Evaluation Summary – Supplemental Study

| | | Supplemental Gas Sites | |
|---|---|---|---|
| **Criteria/Subcriteria** | **Weight** | **Jack County** | **Johnson County** |
| Air Quality Impacts | 4 | 10 | 8 |
| Electrical Transmission | 10 | 6 | 9 |
| Fuel Supply | 10 | 11 | 11 |
| Heavy Equipment Delivery | 2 | 4 | 10 |
| Public Impacts | 5 | 7 | 3 |
| Water Supply | 10 | 10 | 8 |
| **Weighted Totals** | **41** | **353** | **347** |

# SECTION 5.0

# CONCLUSIONS

# 5.0 CONCLUSIONS

The chapter presents the conclusions reached as a result of the investigations and evaluations conducted during the Supplemental Study. Following these conclusions is a summary of the more significant characteristics at each of the two evaluated sites.

## 5.1 SITING STUDY CONCLUSIONS

The conclusions reaching from this study are presented below. For convenience, these conclusions are organized by their primary subject matter.

### 5.1.1 General

- Subject to the limitations that may be imposed by regulatory and permitting agencies, both the Jack County and Johnson County site areas are capable of accommodating the development and insertion of additional gas-fired generation. Both sites scored very well in relative comparison to previously examined sites in the 2002 Study and either site appears to be a viable option.

### 5.1.2 Environmental

- The existing air quality at both the Jack County and Johnson County sites is such that obtaining an additional air emissions permit for the proposed supplemental generation should be practical. However, based upon Johnson County's non-attainment status, there are minor differences between site areas in the relative ease of obtaining this permit.
- It appears unlikely that conflicts with protected species will be a significant concern at either site area given the types of habitat available.
- It appears unlikely that plant expansion would result in significant wetlands impacts at either site area.

### 5.1.3 Electrical Transmission

- Development at either the Jack County or Johnson County site area will require some transmission improvements. These improvements include construction of new transmission lines, the reconductoring of existing lines, or both.

### 5.1.4 Fuel Delivery

- Although both site areas are located near multiple large diameter natural gas pipelines, this does not guarantee that the proposed site will have a reliable supply of natural gas. Some of these pipelines may lack the requisite delivery capacity or pressure. However, based on the quantity of pipelines and the presence of multiple entities near the sites, it is unlikely that significant upgrades would be required to support supplemental generation at either site.
- Because the planned combined cycle generating units are targeted for intermediate service, they should have a high capacity factor. Because firm natural gas delivery may be unavailable at times, particularly during the peak winter heating season, a single interruptible natural gas delivery contract may not be acceptable for these generating units. Moreover, due to the rapid increase in residential and commercial development in the Dallas-Fort Worth metropolitan area, the length or frequency of these interruptions are likely to increase in the future. Therefore, multiple gas delivery contracts are recommended to fuel the generating units in the event that a firm contract is unavailable.

### 5.1.5 Water Supply

- The water requirements at a combined cycle generating unit are relatively high. The most practical water supply at the Jack County site is surface water and at the Johnson County site is reclaimed wastewater. Delivery of additional water may require upgrades or renovations to the existing infrastructure in order to accommodate the additional influx of water.
- Groundwater may be a potential water source at these site areas. A groundwater investigation and possible pump tests may be necessary in order to ascertain groundwater availability, quality, and dependability.

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